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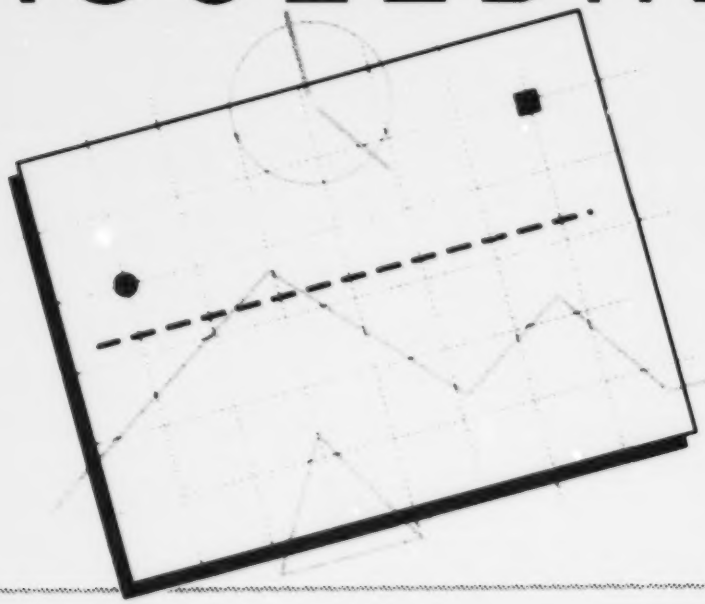

INNOVATIONS IN DISTRIBUTION LOAD MANAGEMENT

Ontario

Energy leadership. For economic strength.

ENERSEARCH

Ministry of Energy

Lyn Mcleod
Minister

November 29, 1989. Toronto, Ontario.

91-00925/

Innovations in Distribution Load Management Seminar

Wednesday, November 29, 1989

Skyline Toronto Airport Hotel
655 Dixon Road
Toronto, Ontario

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Ladies and Gentlemen:

I am delighted to welcome you to our first Enersearch Information Transfer Seminar. A number of Ontario companies, with the assistance of the Ministry of Energy's EnerSearch Program, have successfully developed technologies that impact on energy efficiency. This seminar is intended to highlight technology developed under the EnerSearch Program and to provide you with a broad overview of recent advances in distribution load management.

The papers presented describe new technology, case studies and a utility and industry perspective. It is hoped that this seminar will offer new insights on load management and an appreciation for the potential benefits.

Jack Klieb

Chairman

Distribution Load Management Seminar

Ontario Ministry of Energy

Good Morning Ladies and Gentlemen.

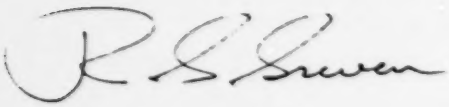
The original purpose of this seminar was to highlight one of the interesting new energy technology development projects funded under the Ontario Ministry of Energy's EnerSearch Program.

EnerSearch will fund up to 50% of innovative energy technology development work to a maximum contribution of $500,000. Each of these adjectives are important. Projects must have a substantial energy impact and must involve a level of technical, as opposed to commercial risk. Since 1986, we have approved funding of $6.8 million for 62 projects.

Rather than telling you more about EnerSearch, it is probably more interesting for you to watch a new videotape that describes the program and highlights six interesting projects.

Literature on the program is available at the EnerSearch booth outside in the hall.

I am here for the rest of the day and would be pleased to discuss EnerSearch in more detail with you.



Robert G. Greven

REMARKS BY

FRANK YOUNG
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PALO ALTO, CALIFORNIA

"LARGE SCALE APPLICATIONS OF LOAD MANAGEMENT"

AT

INNOVATIONS IN DISTRIBUTION LOAD MANAGEMENT SEMINAR

SKYLINE AIRPORT HOTEL
TORONTO, ONTARIO

WEDNESDAY, NOVEMBER 29, 1989

Large Scale Applications of Load Management

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November 29, 1989

Abstract

Electric power systems in the world have been designed to meet certain criteria and to perform certain functions. Today new functions and requirements are being placed on these systems which are stretching its capabilities. Load management in its traditional sense deals with control of the customers load to shift peaks or provide incentives for using electric service at different times of the day. A much broader concept of load management, however, can be visualized in the context of new technologies that are emerging today.

New technology emerging now from the laboratory offers engineers the hope of solving some problems inherent in the present network design and in offering new services to utility customers. Power electronic control of current flow may allow increased loading of existing circuits and facilitate an increasing number of transactions among utilities. Computer and communication advances will contribute to operation of systems closer to their design limits. And in the longer term discoveries such as high temperature ceramic superconductors may revolutionize the way we deliver power to utility customers.

Introduction

Certain fundamentals must not be forgotten in a world of rapid change. These fundamentals are of particular importance to the discussions of transmission and distribution and their roles in a changing utility business environment.

Any discussion of electric power systems must be based on a framework of sound technical considerations. The system is a machine -- perhaps the largest, most complex machine ever built by man. It was designed to perform certain functions. It has a limited degree of flexibility within its design permitting it to perform certain additional functions not originally conceived by its designers, **BUT** it can not do everything. For example, it was not designed to allow large blocks of electricity to go in search of competitive markets. It has limits imposed on it by its very design specifications. Understanding those specifications and the limits they impose must be an important part of any discussions of the transmission issue.

This paper presents a researchers view of the power system and its capabilities. Researchers have some freedom not available to the traditional power system engineer. They can dream of innovative technologies and invention of new concepts and devices, generally uninhibited by the day to day pressure of supplying electricity to customers. Engineers, faced with constraints and limits to their day to day operation of the power system, also dream and apply their talents to extend the capability of the existing system through clever application of the technology available to them. But, this is usually within the context of equipment available in today's market. Over the years the combination of these two view points has resulted in the highly complex, reliable machine that supplies electricity needs to a diverse set of users.

Background

The electric power systems have evolved over a 100 year period. They began as small neighborhood radial distribution systems supplying home lighting. Today a tremendously complex interconnected network provides power requirements for factory, shop, and home. The system has three basic design criteria:

- It must supply electricity on demand. When you turn on the switch, the power must be there to perform the service desired. Therefore, the system must be designed to withstand the loss of, at least, one major component without disrupting the operation of the system. Redundancy in the design of the system ensures an adequate level of reliability.

- It must operate at a constant frequency. The 60-Hertz frequency supplied by the system must not vary more than a fraction of a percent over the course of a day. We have used this characteristic to keep time, design precise industrial processes for making things, transmit information, keep people alive, and accomplish scores of other tasks.

- It must provide constant voltage. Apparatus and appliances are insulated to withstand standard voltage levels thus providing both safe and economic operation of the system.

System Constraints

Today a large part of high voltage electrical systems throughout the world are heavily loaded much of the time. Reasons most frequently cited for this situation include an increase in transfers of large blocks of power among utilities over long distances, a reduction in the number of new transmission lines constructed over the past several years, increasing numbers of utilities, cogenerators and small independent power

producers using the network and generally improving economic conditions within many utility service territories resulting in increasing loads.

The growth in power transfers and intersystem sales in the United States, for example, have exceeded the rates of growth of both load and generating capacity additions in recent years.

At the same time, acquisition of new rights-of-way and construction of new transmission lines have become extremely difficult for a variety of environmental, regulatory and public policy reasons. The only viable and economically attractive alternative then becomes increasing the transfer capabilities of existing rights-of-way and circuits.

The need for greater utilization of the existing system and the resultant increase in competition for the existing system capability among prospective users does not imply a lack of planning by utilities. It simply implies that changes in load growth, fuel prices, power plant additions, and a host of other key external variables have caused many transmission systems to take on functions which were not anticipated in the past.

Utility engineers use a variety of recourses to deal with these limits to extend the capabilities of the existing system when new facilities are delayed or cannot be built. These range from bulldozing a swath under existing lines to allow more sag during critical heavy loading periods to application of sophisticated controls to permit operations of the system closer to its design limits. Load management is one such recourse.

Basic Issues

While it can be shown that engineers can apply their skill and training to make incremental improvements in system operation, support of new energy services by utilities may well require addition of new facilities or extensive modification to the existing system. Several basic technical issues must be considered in any discussion of increased utility service.

Perhaps the most fundamental consideration is whether lines go where power is to be delivered. For example, a utility or power pool may have designed its system for a basic east-west flow pattern. Now if new opportunities or requirements suddenly arise where large north-south transactions are needed, lines may not exist to handle the flows. To attempt to operate this system without building new lines may cause voltage or stability problems or result in inadvertent flows through neighboring systems which are undesirable. This is an expanded view of load management.

Control of the system is extremely important because of the voltage, frequency, and supply on-demand criteria used to design the present system. Today's system is divided into a number of control areas under the supervision of a single operator who orders units on and off line to match load requirements, ensures an adequate operating margin, and oversees voltage and frequency standards. Any new system based on an extension of the present system must have adequate provision for operator control. Rules must be established and participants must adhere to these rules if voltage, frequency, and supply-on-demand requirements are to be maintained.

Re-evaluation of these criteria is, of course, possible and perhaps desirable, but the economic impact of dramatic revisions in any one of these criteria must be properly evaluated before any changes are made. Other operating philosophies are possible and are in use elsewhere in the world. Great Britain, for example, does not have the same exacting frequency standards for its system as we use in the exacting frequency standards for its system as we use in the U.S.A. System operators in the USSR depend on quick restoration of the system following an outage rather than by providing a large degree of redundancy in their system to ensure reliability. Emerging technologies may suggest other operating modes which may better suit a deregulated, competitive utility business environment.

The reliability criteria must be given special attention in any discussion of the transmission issue. The present system design is based on a criteria which allows the loss of a major component of the bulk power system without interruption of service. Spinning reserve and redundant circuits are provided to accomplish this requirement. In a competitive market for electric power, policy makers must consider technical as well as pricing alternatives to decide who will provide reliability, and how it will be best accomplished.

Whether it is done at the generation-transmission level or at the distribution system-customer level will make a difference in the technology used and in the way services are priced. Either appears feasible, but both may require significant technological developments before they can be implemented. Reliability (and quality of service which has not been mentioned here) is a basic issue in this discussion. Can it be provided economically by a utility or another party? This is a fundamental question.

Research Opportunities

Research opportunities abound. Dramatically improved communication capability is one of the important technological developments required for the system of the future, and it is essential if the deregulated, competitive electricity market is to become a reality. In some systems today, both operators and computers have a difficult time conversing because of the

limits in the communication channels and the variety of protocol systems that are provided by different vendors. EPRI is beginning a large program in this area aimed first at computer to computer communication, next at the channel requirements and capacities, and finally at integration of all components into a system that can meet the special needs of utilities in the future.

Flexibility through use of silicon science is another major research area now receiving attention at EPRI that could have a major impact on utility system operation. Systems today are mechanically controlled for the most part. The speed of response is slow. If control could be achieved at electronic speed with "smart" power electronic devices, great strides could be made in increased loading of the existing transmission and distribution systems and providing more flexible systems in the future. The first element in this work is to develop large semiconductors capable of handling power-class voltages and currents and incorporate modern chip technology in the same device. Next, circuits must be developed that can utilize the characteristics of these "smart" power electronic devices to perform power system functions such as controlling voltage, impedance, and phase angle. Finally, actual hardware must be developed, tested, and demonstrated on host utility systems. The Flexible AC Transmission and Distribution System (FACTS) of the future may well dispatch impedance and phase angle as well as kilowatts. In the distribution system the opportunity exists to tailor loads to the customers needs. "If the customer needs a square wave, we will provide a square wave" through application of power electronic devices at his service entrance.

Finally, control functions must be developed in a parallel effort to match the capabilities of the flexible power electronic apparatus. Control, protection, and automation are being discussed vigorously in terms of the productivity improvements that can be realized from their implementation, but when viewed from the perspective in terms of a more competitive electricity market, they also become a vital and key element.

But one question that must be asked is "what margin exists in the electric power system?" It has been designed and built over a 100 year period by our grandfathers, fathers and now by us. Determining these numbers will be a difficult process.

A recent example illustrates this problem: Several years ago San Franciscans celebrated the 50th anniversary of the opening of the Golden Gate Bridge. One of the events accompanying this celebration was a pedestrian walk simulating the one made on opening day. Planners anticipated about 50 to 60 thousand people would be in attendance, but approximately 800,000 people crowded onto the bridge span. A photographer on the Marina Green took a picture of the bridge and noted a two foot deflection of the roadbed because of the excessive weight of human beings. Fear was expressed by many that the bridge had been irreparably damaged. Engineers frantically searched for the original

calculations and finally found that a margin of 15 foot deflection had been designed into the bridge structure. No permanent damage had been inflected on the historic bridge.

Operators in the future may not be able to know the margins, but improvements in computational techniques appearing on the horizon along with new computing technologies may provide data needed for fast response to the demands of the system. Direct calculation of some system conditions is now possible replacing the slower step by step iterative solutions previously required. Concurrent processing can improve the speed of other calculations proportional to the number of processors used. Neural networks, mimicking the way the human brain performs many functions, offers new opportunities in patter recognition and optimization. The control room of the future may be quite different from today's.

Conclusion

The optimism and technical confidence of engineers is apparent in their work. By combining their abilities with scientists and other technologists, they have developed many wonderfully useful things including an electric power system, a world-wide telephone system, and a remarkable transportation system. They have sent men to the moon, provided observation of distant planets, have provided medical technology to extend our lives, and have done many other things. They are limited only by imagination, the properties of materials they can use, the laws of nature, and available funds.

Given a reasonable specification for a project, they can build devices to accomplish the task. This has been shown in the development of our present electric power system and in the ability of engineers to extend its capability under the severe constraints and limits that exist today.

Challenges facing the electric utility industry are not all technical, but today we have the science and the technology is not far behind to address many of these challenges.

Everything hasn't been invented yet!

REMARKS BY

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TORONTO, ONTARIO

"LOAD MANAGEMENT AS AN ELEMENT OF DISTRIBUTION SYSTEM MANAGEMENT"

AT

INNOVATIONS IN DISTRIBUTION LOAD MANAGEMENT SEMINAR

SKYLINE AIRPORT HOTEL
TORONTO, ONTARIO

WEDNESDAY, NOVEMBER 29, 1989

LOAD MANAGEMENT AS AN ELEMENT OF DISTRIBUTION SYSTEM MANAGEMENT

L.V.McCall ONTARIO HYDRO

Introduction

Load management is an important means to achieve highly desirable improvements in the efficiency of electrical energy delivery. It has been successfully implemented by utilities for several decades to reduce load peaks, and consequently reduce the cost of power purchased, as well as to avoid or delay capital expenditures necessary for increases in capacity.

This presentation outlines the concept of a comprehensive process for managing the operation of a distribution system, in which load management is an important element. A systematically conceived, and executed system management process can provide for maximum utilization of a utility's physical plant, as well as enhancing the quality of service to its customers.

Distribution System Management Objectives

Stated in fairly simple terms, the objective of a comprehensive process for managing the operation of a distribution system is to maximize the utilization of the existing system for energy delivery to customers, while concurrently providing a high level of service to them. Therefore, the process must provide for:

(1) delivering continually increasing amounts of energy without exceeding the peak load capability of the system

(2) minimizing impediments to energy delivery

(3) minimizing the loss of energy during its transportation through the delivery system

(4) maintaining high standards of voltage levels at the customer delivery points

Management Process

Information Management

Successful execution of any management process is contingent upon the extent to which information relating to it is managed. Complete and accurate information, retrieved in a timely manner is needed for correct decision making, control implementation, and activity verification.

Information management is a basic function in distribution system management. Irrespective of the degree of sophistication of the management system, accurate, timely and complete knowledge about the distribution system is required for its effective management. All of the distribution management functions described herein depend on an effective information management system for successful operation.

Information management is a continuous process involving both retrieval and processing. The system is monitored for status indications, and analog values. Information processing includes analysis to determine the state of the system, as well as to verify the correct implementation of control actions. In more sophisticated management systems, information management operates in a real-time environment.

Load Management

As previously stated, load management is an important element in a distribution system management process. It plays a very significant role in achieving the objectives previously stated, particularly in enhancing the energy delivery capability of an existing system.

Load management is executed by remotely controlling individual customer loads to achieve desired reductions in aggregate system loads, without inconveniencing the affected customers. Appropriate suppression or biasing of cyclical loads on a rotating basis, or exploitation of energy storage facilities are commonly employed techniques.

For a perspective on the extent to which load management contributes to achieving the objectives of effective distribution system management, consider the following:

(1) Direct load control and/or the utilization of energy storage techniques enables the control of system load values to not exceed system capacity, without constraining the capability to deliver energy. This is the classic role of load management, providing a major contribution to maximizing system utilization by removing or deferring the need for system capacity increases.

(2) Direct load control may make other significant contributions to system management objectives. Service restoration following a prolonged, and extensive outage can be facilitated if non-essential customer loads can be temporarily suppressed to offset the loss of diversity which will occur for such an event. Also, in the event of loss of a major system element,e.g., a substation power transformer, suppression of non essential loads via load management control will enable the continuation of

a reasonable level of energy supply to all customers. Thus, impediments to energy delivery can be minimized.

(3) Load suppression to avoid/defer requirements for additional system capacity results in reducing system losses.

Reliability Management

System reliability management is the process which is executed to minimize the impact of faults on distribution systems. The process provides for rapidly identifying and isolating faulted line sections, and restoring service to unaffected sections by causing the appropriate switching to take place. As described above, load management capability can contribute to the successful completion of service restoration by suppressing non essential loads to facilitate re-energization. The process just described represents an advanced degree of sophistication in system management.

Efficiency Management

As the name implies, this process operates to maximize system efficiency and energy delivery capability by minimizing electrical losses. The process includes the following:

(1) Connecting/disconnecting shunt capacitors to effectively offset lagging reactive currents. Substantial loss reduction is achievable by appropriate VAR deployment.

(2) Peak suppression by invoking load management. As noted previously, this is effective in reducing losses.

(3) On more complex systems, where multiple configurations are achievable, loss reduction can be obtained by reconfiguring as necessary to balance loads on all feeders.

Voltage Management

This process is dedicated to maintaining adequate voltage levels throughout the system. Voltage levels are affected by such factors as load magnitudes, load distribution, and load power factor, and by circuit impedances and configuration. Control of voltage levels is achieved by control of voltage regulators, and shunt capacitors.

The voltage management system can also provide a degree of load management. Controlled reduction in voltage levels across the system, or part of it will result in load reductions. The percentage of load reduction achievable is roughly equal to the percentage voltage reduction.

An Integrated System

The benefits obtainable by implementing load management can be substantially enhanced by incorporating it into an integrated and comprehensive distribution management system. The several elements of an integrated system will benefit by sharing information retrieval and processing capability, telecommunications facilities, and management system/distribution system interface hardware. As indicated in the foregoing, there is considerable interaction between the several management processes. Load management contributes to the successful execution of other processes and vice versa.

Full implementation of a management system for electrical distribution systems, as described in this presentation implies an advanced degree of sophistication. This would be provided by a SCADA or distribution automation system.

Conclusion

There is a strong commitment to load management because it offers substantial benefits in avoided/deferred costs for capacity increases at all levels. The benefits can be significantly enhanced by incorporating load management into a comprehensive distribution system management process.

REMARKS BY

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"LOAD MANAGEMENT: A DESIGN AND OPERATIONS PERSPECTIVE"

AT

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LOAD MANAGEMENT - A DESIGN AND OPERATIONS PERSPECTIVE

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Acres International Limited

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North York Hydro

In recent years the utility industry has been placing increasing emphasis on managing customer loads to reduce the system peak in order to displace new generation facilities or decrease demand charges. This growing interest in demand-side management complements the traditional focus of utilities which has previously concentrated mainly on ensuring that the supply of electricity meets customer needs. In future, we will all be increasingly thinking about how and why customer needs are changing and how we as utilities can influence these needs.

In Ontario, the extent to which demand-side management will be practiced and the details of how it will be implemented are still unclear. What is apparent however, is that many distribution utilities will consider and adopt some form of load control in order to modify their system load curves to reduce their cost of purchased power. These load control strategies may involve direct methods for turning on and off customers' loads by remote control or they may be based on indirect methods using incentive rate structures such as time-of-use rates at the retail level.

In this presentation we will explore some of the impacts load management activities will have on the distribution system itself and on its operation. Most reviews of load management consider either the behavior of individual loads or the aggregate effect of thousands of individual loads as seen from the generator bus. Between these two extremes lies the distribution system and relatively little attention has been paid to its behavior in the emerging world of demand-side management.

Controllable Loads

Load management begins with identifying loads that could potentially be controlled. Whether control action is direct or indirect and whether it is voluntary or mandatory, any load being considered for control must have certain technical characteristics.

Deferable Loads

The simplest types of loads to control are those where customer use is deferable. For example battery charging for industrial in-plant vehicles, irrigation of farm crops, or clothes drying in residences

might be deferable. In each case the customer might accept a delay of an hour or more with little or no inconvenience.

Aside from the control device there would be no need to modify the load itself. Under load control, the customer simply takes delivery of the same amount of energy but at a different time. As a result, there is no change in the installed demand of the load.

Deferable loads offer considerable control flexibility because they could theoretically be scheduled at any time during the system off-peak period. The degree of flexibility for each type of load depends on the number of hours each day that it normally operates. For example, in an industrial plant with day-shift operation only, a 6-hour battery charging cycle could be scheduled any time during the 16-hour after-hours period. In contrast, there may be relatively little flexibility in controlling irrigation if dry weather conditions require operation for more than about 16 hours per day.

Energy Storage Loads

A second type of load that can be controlled is one where energy is stored in the load so that energy does not have to be supplied at the moment in time when the customer uses it. The most obvious example of this is hot water heating where the volume of hot water stored in the tank provides a buffer for matching energy input and output rates. A less obvious example of energy storage loads are space heating and air conditioning. In these cases the thermal capacity of the building allows some leeway in exactly when the heating or cooling system operates.

The obvious thing to do with a storage load to enhance its availability for load management is to increase its energy storage capacity. Larger hot water heaters can supply hot water over a longer period without electricity than can smaller ones. In the US there have been a number of trials where air conditioning requirements are provided by ice made during off-peak times. Room heaters using ceramic blocks to store heat at night and release it throughout the day have been in use in Europe for many years and several experiments involving central heating systems along the same lines have been conducted in North America.

Like deferable loads, those which store energy basically result in a shift in the time of energy use. In contrast to deferable loads however, their demand characteristics may have to be altered in order to allow changing their time of operation. For example, the heating element in a normal space heating system will be smaller than for an equivalent storage system where the energy required for a full 24 hours is compressed into 12 hours or less. All else being equal, the installed demand for an individual load will have to increase as the time period over which it is required to operate is reduced.

Cycling Loads

An alternative to increasing the energy storage capacity of a load to enhance load management is to use a relatively short cycle time for control. Summer peaking utilities in the southern US control conventional air conditioning loads by dividing them into groups and sequentially turning each group off for a few minutes each hour. For example, if each of 10 groups is turned off for 6 minutes per hour, at any moment only 90% of the load will be present.

This load management strategy is only effective for loads that would be operating close to 100% of the time anyway. During summer peaks, air conditioning is such a load with virtually all units running at capacity for many hours at a time.

System Voltage Reduction

To complete the catalog of types of controllable loads it is necessary to mention the possibility of using a system-wide voltage reduction. System demand will drop by between 2.5% and 4% immediately after a 5% cut in voltage, with the range depending on the particular load make-up, time of day and season. The demand reduction slowly disappears however and it is generally felt that 30-60 minutes after starting the voltage reduction the demand is no lower than if the voltage had not been reduced.

Voltage reduction is widely used by many utilities throughout the world as a means of reducing system peak demand. Although some Ontario utilities also routinely reduce voltage, it is usually seen as an emergency measure reserved for use by Ontario Hydro.

Rebound Demand and Deferred Energy

Power systems are designed on the basis that the on and off action of individual loads occurs randomly. When load management strategies are implemented however, some of this randomness disappears because the operation of different groups of loads are compressed into certain time periods and excluded from others. It therefore becomes important to consider some of the characteristics of loads during the period after they have been turned on.

Inrush Current

When any load is first energized it draws an initial inrush current. This is most pronounced for motor loads where current during the initial seconds or fractions of seconds can exceed ten times normal operating values. Other types of loads have similar inrush effects but are generally less pronounced.

With some load management strategies there is the possibility of energizing many individual loads simultaneously so that the

individual inrush peaks coincide and cause a current peak for the system. This could cause a momentary drop in voltage which will tend to stall motors thus prolonging and increasing the current inrush. In the extreme, these peaks could operate system protection and fuses.

Loss of Diversity

After the initial inrush current each individual load settles at its normal operating level. Under some load management schemes however, the effect could be similar to a 'cold load pick-up' situation that occurs after a prolonged outage. Because under load management many loads are energized simultaneously or in close succession, the normal diversity between them is lost and the system sees a larger aggregate load than existed just before the same loads were turned off.

For example, uncontrolled water heaters cycle on and off depending on the various rates of hot water use. At the beginning of a load control cycle perhaps only 40% of them are actually operating. During the off period in the load control cycle customers will continue to draw hot water with the result that the thermostats in all units will call for heat. When they are reenergized at the end of the load control cycle 100% of the water heaters will be operating. They will therefore present a load to the system that is 2.5 times larger than before (100/40).

In this example, load management has caused a loss of diversity from 0.4 to 1.0 with a resulting increase in load. Diversity will be regained and the aggregate load will fall back to normal levels after some period ranging from a few minutes to a few hours, depending on the characteristics of the load controlled. Although all load management strategies have the potential for losing diversity, the storage loads are generally a greater concern than the deferable loads.

Deferred Energy

Although both deferable and storage loads facilitate load management by allowing energy use to be time shifted, in fact load management can also alter the amount of energy used. For example, the energy used by an air conditioner depends on how long it runs and the torque imposed by the compressor on the electric motor. If operation is deferred so that a greater proportion of running time is during a hotter part of the day, both the running time and compressor torque increase. The greater temperature differential due to higher outdoor temperatures means not only that more heat must be transferred resulting in a longer running time, but also that the compressor torque will be higher.

A second example is when heat pumps are subject to load control. If the control strategy moves operation toward cooler parts of the day there will be proportionately greater use of the electric resistance

backup heater units. This has been found to increase not only the energy use but also the average peak demand.

In these examples load management has increased energy use because the deferred energy is higher than the normal energy. Other load management alternatives also have deferred/normal energy ratios greater than 100%. The basic reason is because deferring use or storing energy inherently involves some loss in efficiency.

System Hierarchy and Impacts

Electric power systems are arranged in a natural hierarchy of generation, transmission and distribution. Going down through this structure from generation toward individual customers, each piece of system equipment serves fewer and fewer customers. On the distribution system itself this pattern continues with substations serving thousands of customers, feeders hundreds and distribution transformers dozens.

The importance of this arrangement in the perspective of load management is that equipment at lower levels of the hierarchy have less diversity in their loads than at higher levels. The decrease in diversity has both time and geographic aspects.

Temporal Diversity

Temporal diversity is the same concept as outlined above with respect to the loss of diversity with controlled loads. Temporal diversity occurs because different loads operate at different times. At higher levels in the power system hierarchy such as at a substation, the on-off cycles of thousands of individual loads become indiscernible and the aggregate load appears as a relatively constant average value from one hour to the next.

In contrast, at a distribution transformer the on-off behavior of individual loads can affect not only the average load but also the peak and minimum demands. Distribution transformers will therefore be subjected to a wider range of load demands than substation transformers. Following the same logic, feeders will see slightly more diversity and smoother load curves than distribution transformers because they are the next level up in the hierarchy.

From this it can be seen that all distribution system components will inherently be subjected to greater extremes of load than will transmission or generation system components. Since distribution system components are directly affected by individual loads there is the possibility of localized overloading due to the higher installed and rebound demands resulting from load management.

Geographic Diversity

There is also a geographic factor in that the load at higher levels in the hierarchy is a combination of many types of individual loads. For example, a substation might serve a mixture of residential, commercial and light industrial loads whereas a single distribution transformer would serve only one type.

Again, the effect at the higher levels in the hierarchy is a smoothing of load curves as the characteristics of one class of load offset the changes in another. A feeder serving a predominantly residential load will have greater variations in load than a substation that also supplies feeders serving industrial loads, for example.

As for temporal diversity, it can be seen that the distribution system inherently has less geographic diversity than the transmission or generation systems. Since load management is only possible on certain types of loads, they will be associated with specific customer classifications and therefore clustered geographically. With less geographic diversity, the loading of distribution system components will be affected more by load management operation than transmission or generation system components. Again, the result could be localized overloading even though the aggregate demand at higher levels in the hierarchy has dropped.

Mitigating the Impact on Distribution Facilities

The overall effect of load management on distribution systems is a tendency toward higher localized peak loads. This is the result of a number of factors that come into play when loads are reenergized at the end of a load control cycle. These factors are explained above and can be summarized as follows

- diversity is lost because the natural random operation of loads is compressed into some time periods and restricted from others

- the installed capacity of some types of loads must be increased in order to deliver sufficient energy over a shorter period of time

- the turn-on of loads is concentrated over short time periods so that cold-load pick-up effects of high inrush currents and high rebound demand are aggregated

- distribution system loading is significantly affected by individual load characteristics because classes of loads with similar operating patterns are geographically clustered.

It appears from the discussion to this point that load management is something that should be avoided by distribution utilities. Fortunately, the situation isn't quite that bleak and a number of

simple procedures and design approaches are available to mitigate the troublesome aspects. The approaches are aimed at maximizing the temporal and geographic diversity so that they approximate conditions without load management.

Staggered Turn-On

By simply staggering the turn-on time of loads at the end of a load management cycle, many of the rebound problems disappear. In some load management systems, the turn-on time of individual loads is randomized by including a simple low accuracy timer in each controller.

This is the approach favored in some systems using radio controlled water heaters. Each controller turns the load off for 10-15 minutes in response to a radio command. Longer off periods are achieved by repeating the command at 5-10 minute intervals. When it is decided that normal operation can resume, commands are no longer sent and water heaters are energized as their individual controllers turn on over a 5-minute period.

In other types of load management systems, the controlled loads are divided into groups and the operation of each group is staggered with respect to the others. This would be the approach used by most power line carrier and telephone-based systems where explicit turn-on and turn-off signals are transmitted along with group identification codes.

Geographic Dispersion

By arranging to spread each group of controlled loads over a wide geographic area, the problems of localized overloading due to load management operation can be avoided. Load management systems such as radio or power line carrier systems actually broadcast commands to all receivers regardless of their location. It is therefore quite possible to ensure that each of the controlled loads on a distribution transformer are assigned to different groups.

A load management strategy that staggers the cycling of groups therefore achieves both temporal and geographic diversity to eliminate localized overloading on the distribution system.

Indirect Control

Some degree of randomness and diversity will be retained by leaving the actual control action to the discretion of customers and providing them with only a rate incentive such as a time-of-day pricing. There will be some tendency to concentrate the turn-on of off-peak loads to just after the beginning of the off-peak period, particularly if customers install automated controllers. Indirect load management may inherently result in a greater variety of types of loads and control strategies as the diverse ingenuity and

preferences of individual customers come into play. However, the amount of load that would actually be controlled may be somewhat unpredictable.

Cost of Load Management

Before useful cost estimates for implementing load management can be developed, it is necessary to select the approach to be used. This selection process is a major undertaking and not something to which we can do justice in this presentation.

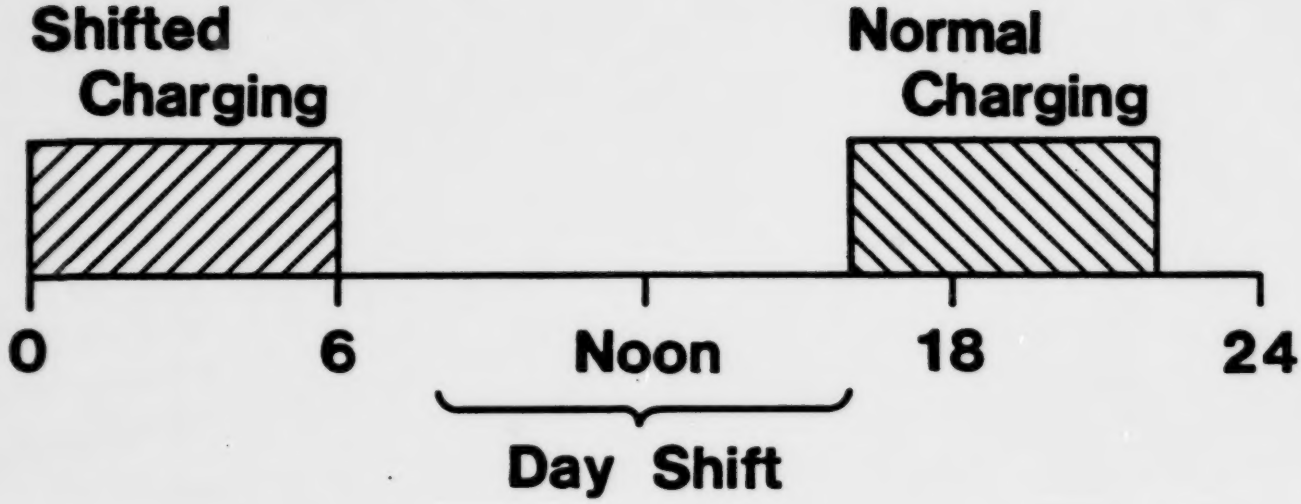
In general, a load management system with some of the features outlined above will require not only control switches as each load but a centralized computer and an extensive communication network. Minimum costs will at least be $150 per controlled point on large systems. Smaller systems will cost more per point because the cost of centralized equipment is prorated over fewer installations. Higher costs can also be expected for the additional software and hardware required for features such as the temporal and geographic diversity. Realistic rough estimates are about $500 per point for a few thousand points ranging to well over $1000 per point for a few hundred.

Conclusions

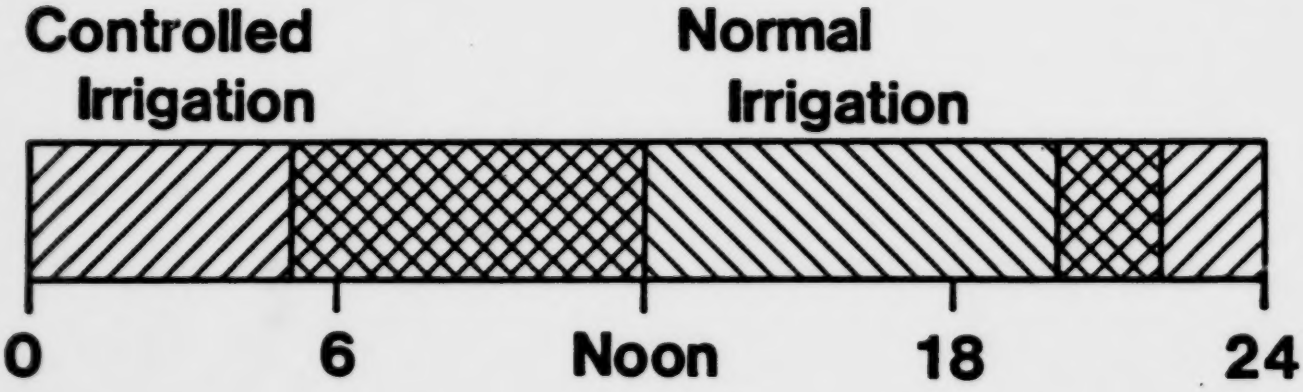
Load management will undoubtedly be an important tool for Ontario distribution utilities to meet the challenges ahead. The pending introduction of time-of-use rates for power purchases is a clear indication that new approaches must be introduced to fulfill the mandate of power at cost.

What we have covered in this presentation is some of the distribution engineering challenges that go along with the introduction of load management. Like most initiatives, load management is not without its pitfalls.

It is important that utilities planning load management systems consider not only the behavior of their customers and the cost of wholesale power from Ontario Hydro but also the impact on their substations, feeders and transformers.



A. BATTERY CHARGING
- GOOD FLEXIBILITY



B. IRRIGATION - POOR FLEXIBILITY

Fig. 1 FLEXIBILITY OF DEFERRABLE LOADS

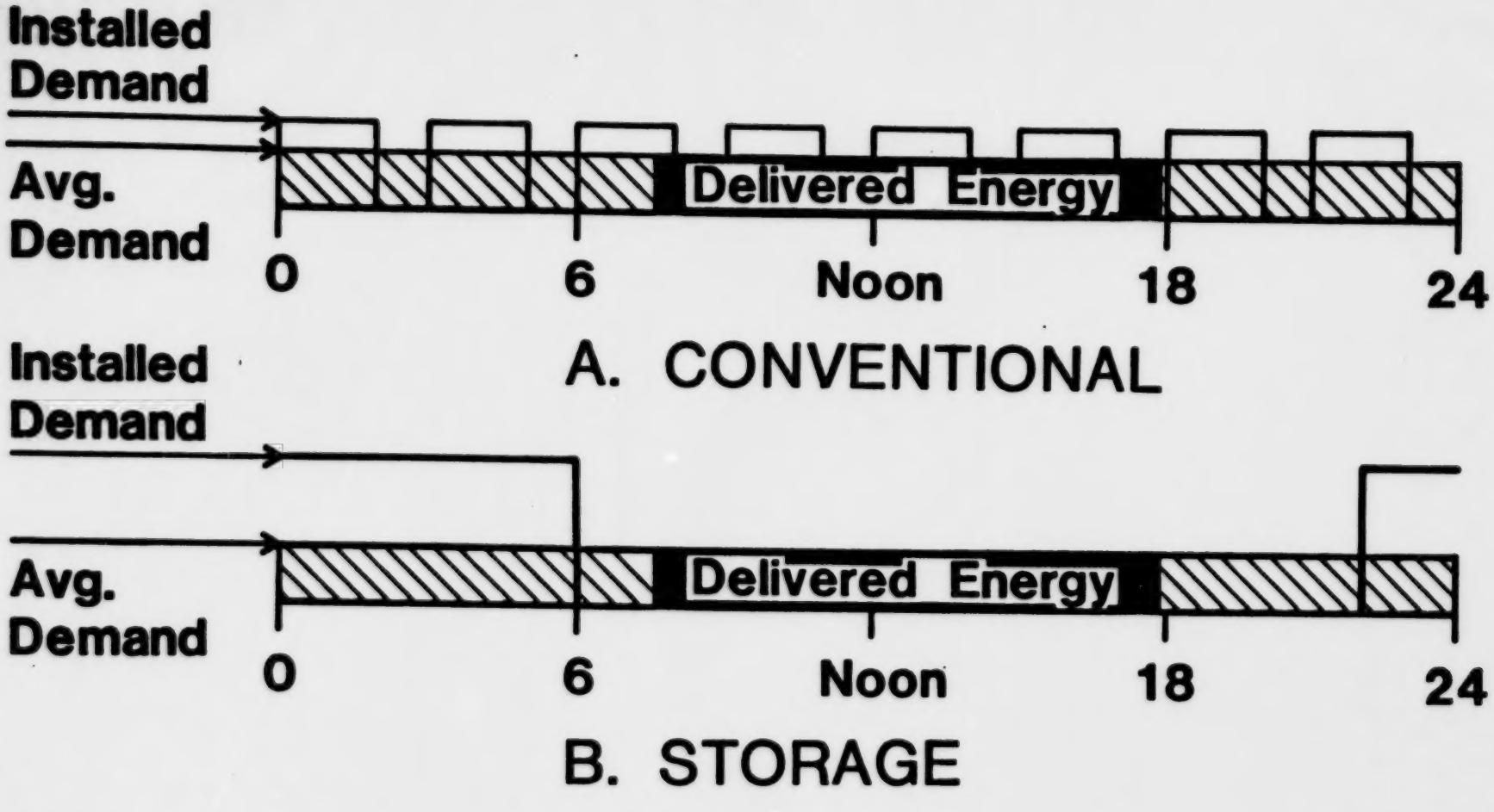


Fig. 2 EFFECT OF STORAGE LOADS ON INSTALLED DEMAND

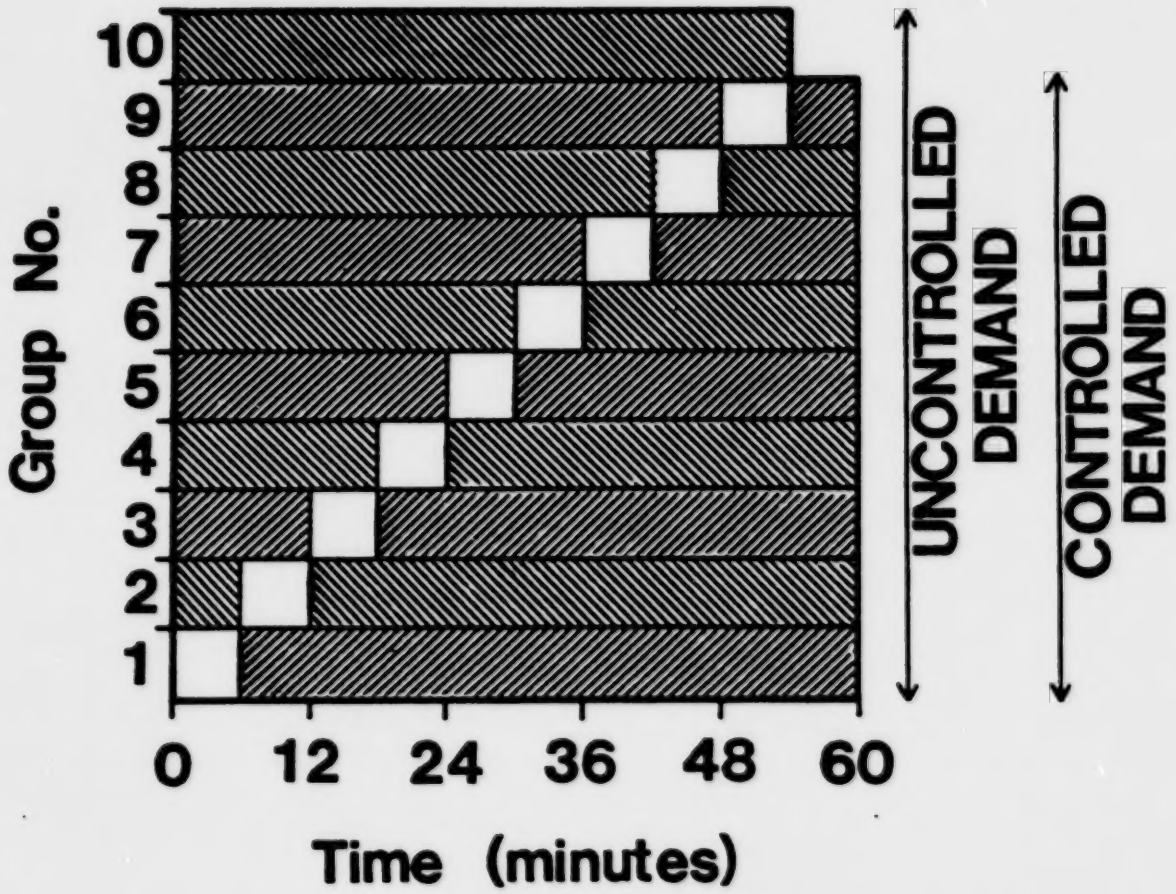


Fig. 3 CYCLING LOADS TO FORCE DIVERSITY

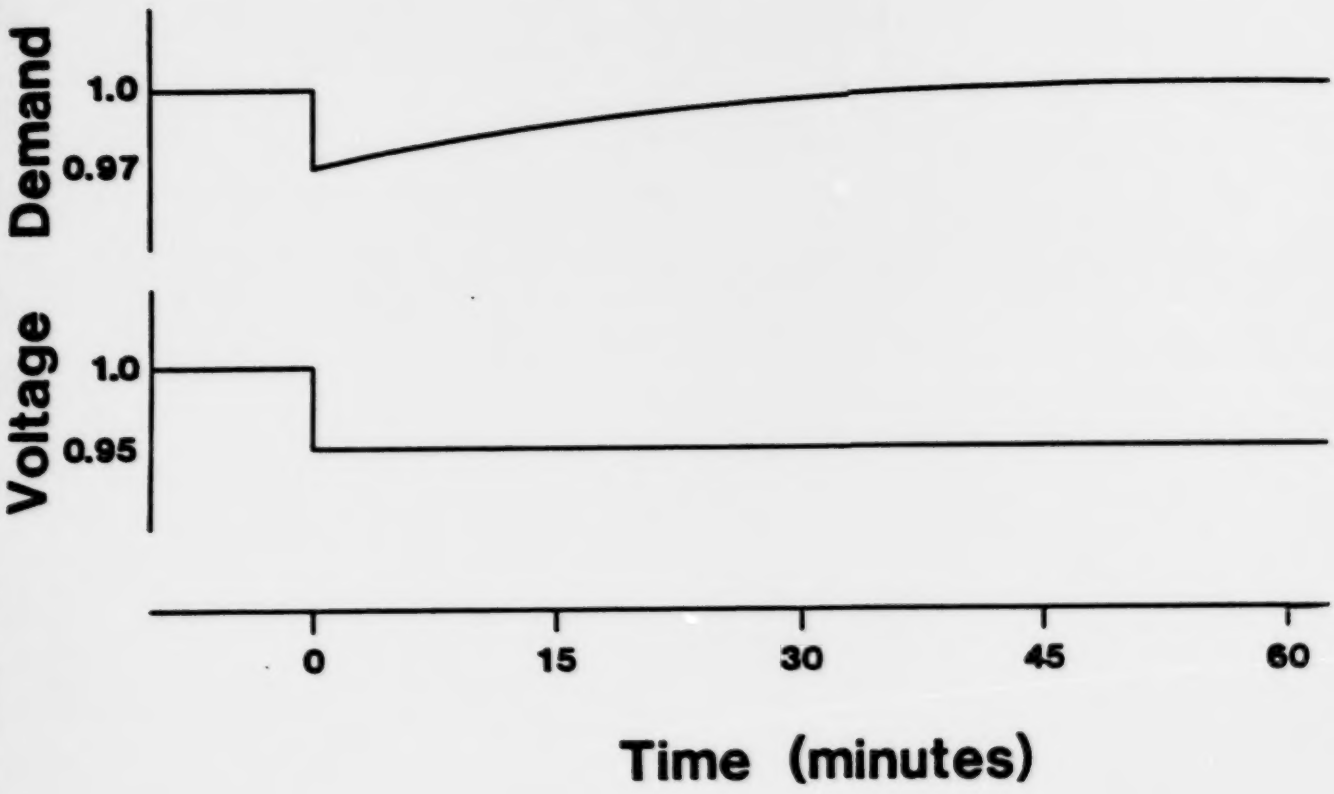


Fig. 4 VOLTAGE REDUCTION

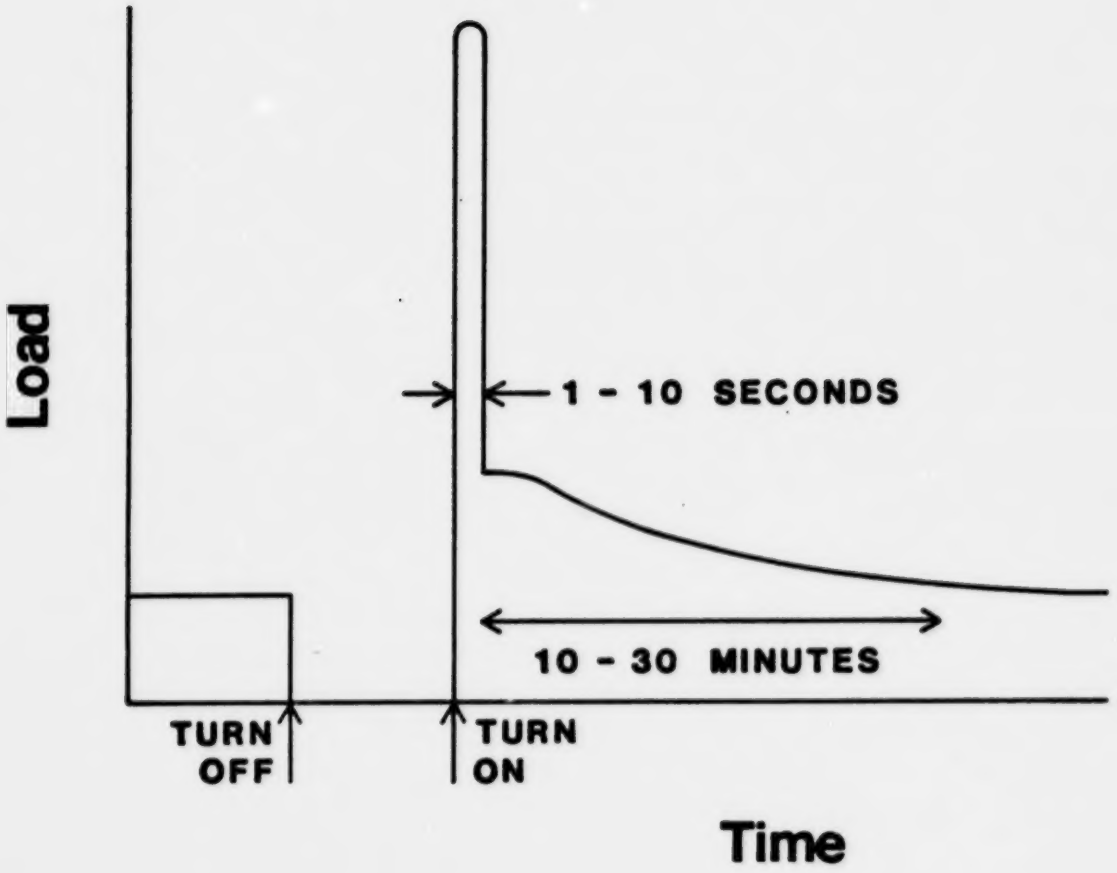
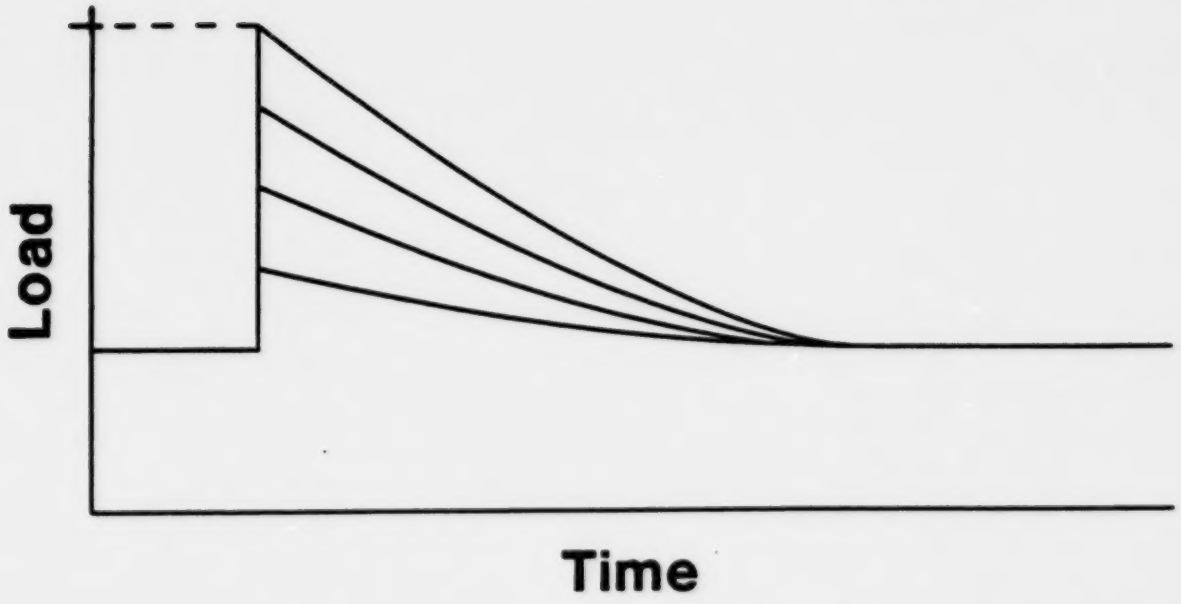


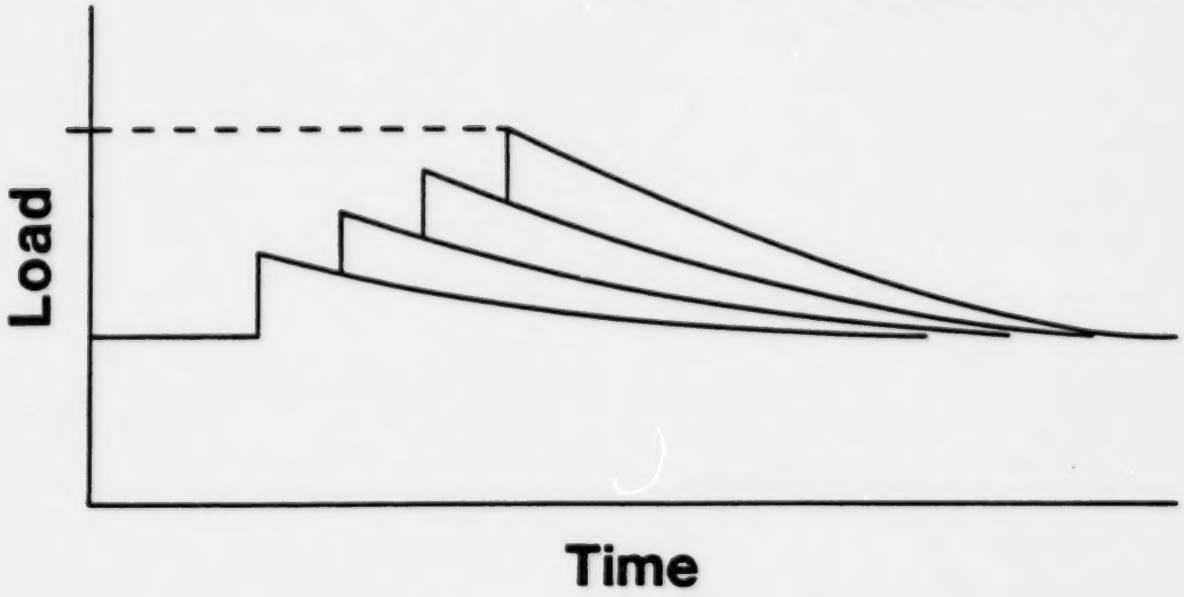
Fig. 5 INRUSH AND REBOUND WITH LOAD CONTROL

LEVEL	VOLTAGE	CONNECTED CUSTOMERS	DIVERSITY	IMPACT OF INDIVIDUAL LOAD
Subtransmission	44kv	5 000	High ↑	Small ↓
Substation	44/27.6kv	2 500		
Feeder	4-27.6kV	500		
Lateral	4-27.6kV	50		
Dist. Transformer	27.6/120V	5		
Service	120V	5	Low	High

Fig. 6 DISTRIBUTION SYSTEM HIERARCHY

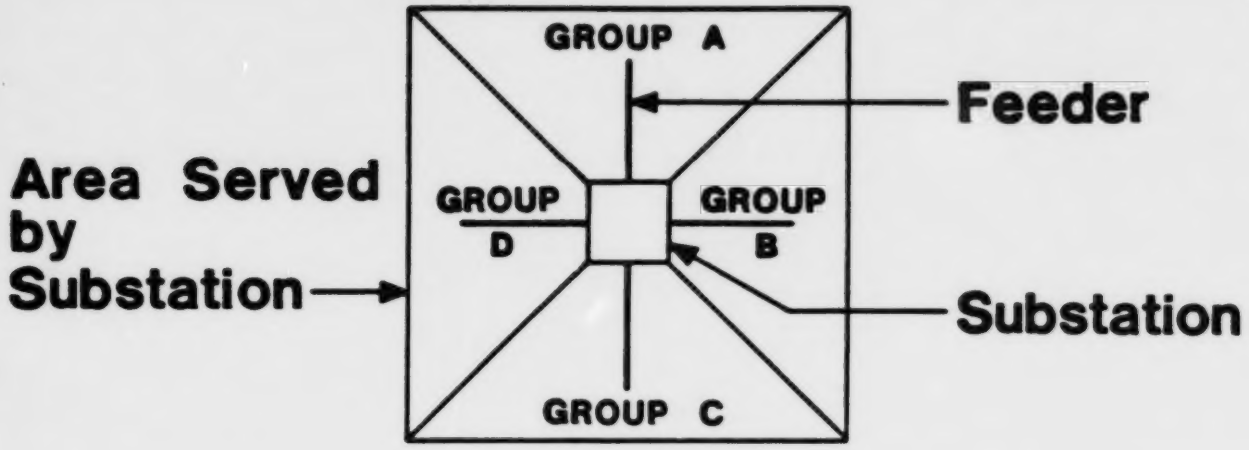


A. COINCIDENT

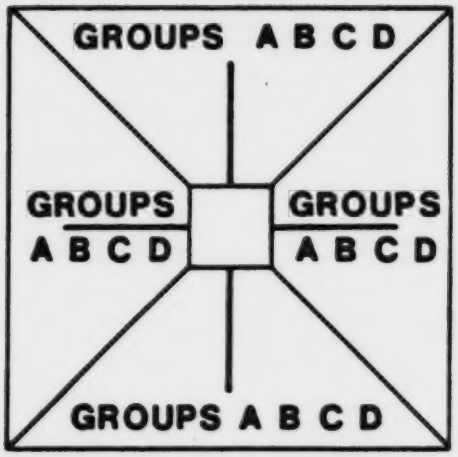


B. STAGGERED

Fig. 7 EFFECT OF STAGGERED TURN-ON



A. CONTROL GROUPS CLUSTERED



B. CONTROL GROUPS DISPERSED

Fig. 8 GEOGRAPHIC DISPERSION

REMARKS BY

LARRY FISH
PRESIDENT
JOMITEK INC.
NEPEAN, ONTARIO

"MICROCOMPUTER SYSTEMS TECHNOLOGY FOR LOAD MANAGEMENT"

AT

INNOVATIONS IN DISTRIBUTION LOAD MANAGEMENT SEMINAR

SKYLINE AIRPORT HOTEL
TORONTO, ONTARIO

WEDNESDAY, NOVEMBER 29, 1989

MICROCOMPUTER TECHNOLOGY FOR LOAD MANAGEMENT

Given at:

Seminar 29-Nov-89

Skyline Hotel

MICRO COMPUTER TECHNOLOGY FOR LOAD MANAGEMENT

As the cost of computer system applications plummet, more and more industrial applications are becoming economically feasible; in particular LOAD MANAGEMENT.

LOAD MANAGEMENT FUNCTIONS

LOAD MANAGEMENT encompasses the following functions:

* ENERGY and DEMAND Monitoring
* ENERGY contract management
* DEMAND Forecasting
* DEMAND reduction through LOAD SHEDDING, including water heaters, large motors, and certain appliances
* DEMAND reduction through PEAK SHAVING Voltage control. This affects the electrical DEMAND, but not energy consumption
* DEMAND reduction through LOAD DISPLACEMENT, typically using gas or diesel powered generators to generate power "ON PEAK"

LOAD MANAGEMENT IN PRACTICE

LOAD MANAGEMENT has in the past been economically unattractive. Micro computer technology and rising energy costs have changed the economics of LOAD MANAGEMENT for large power users.

LOAD MANAGEMENT:

* is a technique of CONTROLLING LOADS on the distribution system to avoid buying high priced power during "PEAK" periods.

* has been identified as a principal means of reducing rising operating costs and improving the efficiency of operations in Ontario.

* is the area I am involved in. My company uses personal computers as the computing element for all of our systems.

Historically the acceptance of LOAD MANAGEMENT technology has been constrained by three factors:

* High data accuracy was required in the measurement of ENERGY, DEMAND and their correlation in TIME because very small changes in the pattern of energy consumption produce very large economic impacts; the control levers available usually have a very small range of control.

  THIS REMAINS TRUE TODAY.

* The scientific number crunching power required to achieve economic results was available only in the largest of computer installations.

  PERSONAL COMPUTERS NOW OFFER ECONOMIC SOLUTIONS.

* Acquiring data from energy meters has previously required very complex and expensive equipment. A high degree of technological sophistication was required to collect data from electro mechanical meters using remote terminal units and to transmit the data via telemetry to a high performance LOAD MANAGEMENT master computer.

  TODAY PERSONAL COMPUTERS CAN BE CONNECTED DIRECTLY TO ENERGY AND DEMAND METERS.

ADVANCES IN COMPUTER TECHNOLOGY

When IBM designed the first commercial computer system (the model 360) in the early 1960's it was believed that the total market for such equipment would be somewhere around 100 systems. The cost of the machinery was high, programming was difficult and the applications therefore very limited.

The first commercial computers were, by our current standards slow, required special water cooled facilities to house them, and specially trained staff to run them.

For example, the IBM 360 computer system we had at McGill University in the late 1960's executed programs at a rate of 250,000 instructions per second, had 64 kbytes of iron core memory and 2 megabytes of high speed direct access disk storage. In spite of these limitations, by the end of the 60's IBM's market estimates had proven to be vastly understated. More than 1000 systems were sold, delivered and installed.

A consequence of this tremendous success was that IBM could not keep up with the demand for new and disparate application software programs to use on their machines, and the third party software industry was born.

Since then the pace of technological evolution of computers has been on constant full force acceleration. Today, a commercial lap top computer executes programs at more than 2 million instructions per second, has 44 megabytes of direct access on line storage, and can be carried in a briefcase.

Fortunately for those of us in the third party software industry, we still cannot keep up with the demand for new applications to use on these machines.

SOFTWARE TECHNOLOGY

The magic and mythology of building new applications lies entirely in the realm of SOFTWARE. One may visualize the internals of a computer, new or old, as millions of switches flicking back and forth at random. In order for the machine to be of any use at all, these actions must be coordinated.

Software is what coordinates the actions of the electronic components inside the computer. Software cannot be seen, touched or examined - it does not assume a physical form - it is entirely conceptual. It is pure logic.

To give you an appreciation of what software development entails, imagine how long it would take to write a policy manual for your organization which consists of one hundred thousand employees - how do you program these individuals to carry out your instructions to the book ?? - yet this is the task of the software program developer. By analogy the programmer writes the execution policy for the millions of individual functions within the computer box.

IMPLICATIONS OF ADVANCES IN PROGRAMMING TECHNOLOGY

I have been involved with automation projects for twenty years. For the first fifteen years of my experience the main costs of automation projects lay in the domain of computer hardware - logic and memory. Labour costs were low and possibly insignificant by comparison.

When planning resources for an automation project we used the rule of thumb which proscribes programmer productivity in terms of writing application programs in computer machine "Assembly" language. A code production rate of 5 lines of code per day per person was used. An application program requiring 1000 instructions took most of a 'person year' to develop.

But the cost of programming was still significantly less than the cost of the computer hardware; therefore, economically speaking, our efforts focused on minimizing hardware costs and optimizing the efficiency of machine code.

During the past five years a major transition has been taking place in the industry. Computer hardware costs have been plummeting, and computer performance has been increasing several tens of times. At the same time labour costs have been accelerating.

10 years ago, a 'person year' of software development would cost an organization between $20,000 and $30,000. Now the costs have tripled, in spite of plummeting hardware costs.

For this reason the technology of programming has become a key factor in costing automation projects.

The economics of the personal computer as a consumer item has compelled a significant evolutionary improvement in the science of programming.

Advanced software development tools have been available for many years. However, they previously required high power, very expensive computing machinery on which to operate, making them to costly for most software development organizations.

Now as we approach the 1990's the economics of computer system design is exactly the opposite of most of my experience. The availability of high performance personal computers (the AT-ISA and MCA-PS/2 machines) has brought the requisite very high computing power to software development laboratory for a very small capital cost.

With advanced software development tools, computer scientists can produce software applications at a very high production rate.

For example, my company is routinely producing code at the rate of 300 lines of code per day. The application that took one 'person year' to develop 15 years ago now can be completed in three to four days using state of the art hardware and software technology!!!

PERSONAL COMPUTERS AND LOAD MANAGEMENT

The personal computer has therefore become the ideal candidate for LOAD MANAGEMENT applications due to its:

* low cost
* high performance
* high reliability
* flexibility
* multiple sourced standard parts
* need for minimal maintenance

My company has installed practical load management systems using personal computers for:

* Mines - Contract Demand Management
* Automotive assembly plants - Contract Demand Management
* Hydro utilities - Contract Management, Load Control, Load Forecasting
* Hospitals - Load Displacement, Emergency Power Supply Management
* Office complexes - Contract Management Load Displacement, Emergency Power Supply Management

CONSIDERATION FOR INSTALLING LOAD MANAGEMENT

LOAD MANAGEMENT required good historical data recording to be useful in LOAD MANAGEMENT:

* ENERGY CONSUMPTION
* DEMAND
* time correlation with the BILLING INTERVAL.

SOME TERMINOLOGY

The BILLING INTERVAL is 15 minutes in the Provinces of Ontario and Quebec. It may also be 30 minutes or 60 minutes depending on the locale and the method your utility has chosen to compute their rates.

The BILLING PERIOD is the number of days of energy consumption encompassed by your electrical bill from your supplier of electricity.

The electrical DEMAND is the TIME rate of electrical ENERGY consumption during a BILLING INTERVAL.

The PEAK DEMAND is the largest single DEMAND value measured during a BILLING PERIOD.

ENERGY CONSUMPTION

Energy CONSUMPTION is measured using electromechanical 'Watt hour' meters. The meter movement rotates at a rate of one revolution for "K" watt hours consumed.

Pulse initiators are attached to the meter movement. The pulse initiator produces a contact closure each time there is one full rotation of the meter. The contact closure is called the meter "PULSE".

THE AMOUNT OF ENERGY REQUIRED TO PRODUCE ONE PULSE IS CALLED THE "METER CONSTANT - K".

Due to limitations electromechanical rotating devices, the pulse rate is never faster than 3 pulses per second.

* My company has successfully applied personal computers to the accurate accumulation of energy meter pulses over extended periods of time.

TIME CONSIDERATIONS in LOAD MANAGEMENT

The accuracy and relative stability of the time clock used for the measurement of energy is a significant consideration.

No clock is ideally stable over the long term. For example, a typical computer clock provides an accuracy of 75 milliseconds in a 15 minute period. Over the period of a month this may result in mismatched billing intervals.

Small differences in the determination of ENERGY CONSUMPTION and DEMAND during a BILLING PERIOD can result in significant economic differences of opinion between the supplier and consumer of electricity.

A TIME SYNCHRONIZATION clock, used to define BILLING INTERVALS for ENERGY CONSUMPTION and DEMAND determinations, is a key component of Contract Management applications.

* My company has successfully built a time synchronization application for personal computers to provide accurate tracking of energy consumption and demand during the BILLING PERIOD

LOAD FORECASTING TECHNIQUES

It is advantageous to have advance information about the time and magnitude of an expected DEMAND peak ahead of time so that appropriate action can be taken at the correct time.

RATE OF RISE Forecasting

A traditional method of forecasting uses the "RATE OF RISE" of energy consumption to predict what the demand will be at the end of the current BILLING INTERVAL. This procedure:

* does not need "MEMORY"
* produces a "STRAIGHT LINE" result. Straight Line Forecasting can be done with an electro mechanical totalizer.

REAL DEMAND Forecasting

Personal Computers now offer a more accurate forecasting technique using an Auto Regressive Moving Average mathematical model. The ARMA method examines past data trends and uses statistical techniques to predict the future. The ARMA method requires:

* a dedicated digital computer
* substantial "MEMORY"
* The ARMA technique predicts the future "SHAPE" of the DEMAND PROFILE

The ARMA technique produces a more accurate, time dependent forecast than was previously available using electro mechanical forecasters.

LOAD CONTROL DECISION MAKING

Load control decision making involves relatively simple control actions including: REDUCE VOLTAGE, or RESTORE VOLTAGE, "FANS OFF" or "WATER HEATER ON".

It does not pay to carry out load control at the WRONG TIME:

* Utilities may suffer revenue loss without reducing their PEAK DEMAND
* There is a potential for DEMAND "FLY BACK" during the time of peak, resulting in significant economic losses

"STRAIGHT LINE" or "RATE OF RISE" predictors become inaccurate just before the actual SYSTEM PEAK throwing the responsibility for decision making back to the system operator. However, it is precisely at this time that the operator most needs the decision support from the LOAD MANAGEMENT System.

Personal computers allow us to use REAL DEMAND FORECASTING techniques to accurately determine, in advance, the time and magnitude of a system peak

Using personal computers it has become straight forward and economically practical to collect energy data from meters at various locations.

My firm has built LOAD MANAGEMENT systems using micro computers:

* located right at energy metering locations
* which send data to other micro computers for processing in a practical, economic manner.
* accurately track energy consumption and demand during the BILLING PERIOD
* incorporate a 2 hour "ARMA" REAL DEMAND forecast
* which use a rule based system. The rule based system incorporates both quantifiable (RATE OF ENERGY CONSUMPTION) and non-quantifiable (TIME OF PEAK IS NOT USUALLY AT 16:00 HOURS) heuristics in its decision making process to reduce DEMAND.

CONCLUSIONS

Today everyone is aware of the coming shortage of electrical energy. Conservation, cost control and improved utilization are key words spoken in corporate board rooms.

My firm's initiatives have demonstrated the practicality, reliability and economy of the technology. We are able to develop systems to monitor demand and carry our demand displacement control strategies.

Micro computers have brought LOAD MANAGEMENT applications within reach of most large power users. They offer innovative solutions for power management demands.

It is fortunate for us that computing technology has evolved in time to help us meet the coming shortages of electrical energy.

With the personal computers we have the inexpensive computing power required to:

* record the large amounts of data required for LOAD MANAGEMENT

* characterize electrical energy consumption from historical data.

* compute complex mathematical demand forecast models, and

* dedicate a computer system to the task of LOAD MANAGEMENT.

* use REAL DEMAND FORECASTING techniques to accurately determine in advance the time and magnitude of a system peak

* use rule based control systems to most effectively implement load controls

* implement complex load cycling schedules to avoid the economic pitfalls of DEMAND FLY BACK

BIOGRAPHY

Lawrence Fish, M.Eng., P.Eng., MBA.
President, JOMITEK Inc.
Nepean, Ontario.

Mr. Fish is a professional engineer with a Masters degree in Electrical Engineering from McGill University, and a Masters of Business Administration from the University of Ottawa.

Mr. Fish spent the last 20 years working with mainframe and mini computers in various manufacturing, engineering and marketing data acquisition and control systems.

Mr. Fish founded JOMITEK Inc. in July 1986 and has supervised JOMITEK's ongoing expansion. JOMITEK is a company involved with design, manufacturing, installation and servicing micro computer based systems. These systems provide efficient and accurate energy management and control for large users of electricity.

Mr. Fish's customers have included pulp and paper manufacturing companies, electric utilities, and large process industries in Canada and the USA.

In October 1987, JOMITEK was recognized by the Provincial Government for its advanced state of the art technology and received a grant from the Ontario Ministry Of Energy to research and further develop energy conservation systems.

JOMITEK soon became a standard, often specified supplier of power management systems and products. Reliable systems, project management expertise and a proven track record of technological innovation has resulted in JOMITEK's rapid growth.

REMARKS BY

IAN MCMILLAN
MARKETING MANAGER
QUINDAR INDUSTRIES
TORONTO, ONTARIO

"SCADA AND INTEGRATED LOAD MANAGEMENT"

AT

INNOVATIONS IN DISTRIBUTION LOAD MANAGEMENT SEMINAR

SKYLINE AIRPORT HOTEL
TORONTO, ONTARIO

WEDNESDAY, NOVEMBER 29, 1989

SCADA AND INTEGRATED LOAD MANAGEMENT

TYPICAL SCADA SYSTEM: (REFERENCE FIGURE 1)

As computers drop in price and increase in power, customers can take ever increasing advantage of the calculation capabilities and the historical data capabilities of our SCADA System. With the recent introduction of Digital Equipment of Canada Corp. (DEC) VAXStation 3100 computers, we have a 4 MIP CPU with a true multi-tasking operating system, 8 to 16 Meg RAM and 50 to 100 Meg discs in the price range of a PS2. SCADA systems which, in the past pushed to the limit the capabilities of older CPU's, are now running 15% to 30% loaded even with high speed multi-port RTU polling, 1-2 second CRT write times, and significant calculation loading.

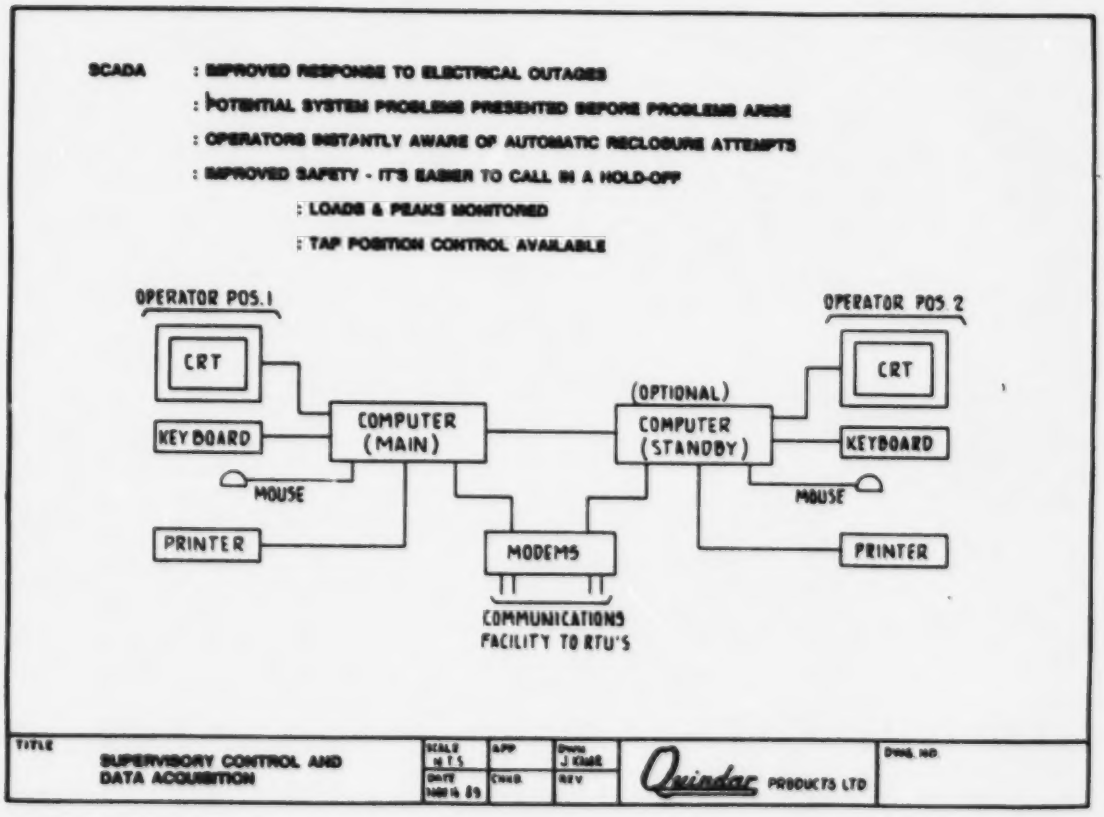


Figure 1

More tools are obviously available so what else can they be used for?

One new SCADA feature which is made feasible by the availability of low cost, larger CPU memory, is the use of X-Windows as an operator CRT interface. (Reference figure 2). Now most operator actions are limited to point and click actions with the mouse. Operators don't have to be typists. One CRT now serves the purpose of 3 or more older technology non-windowing CRT's.

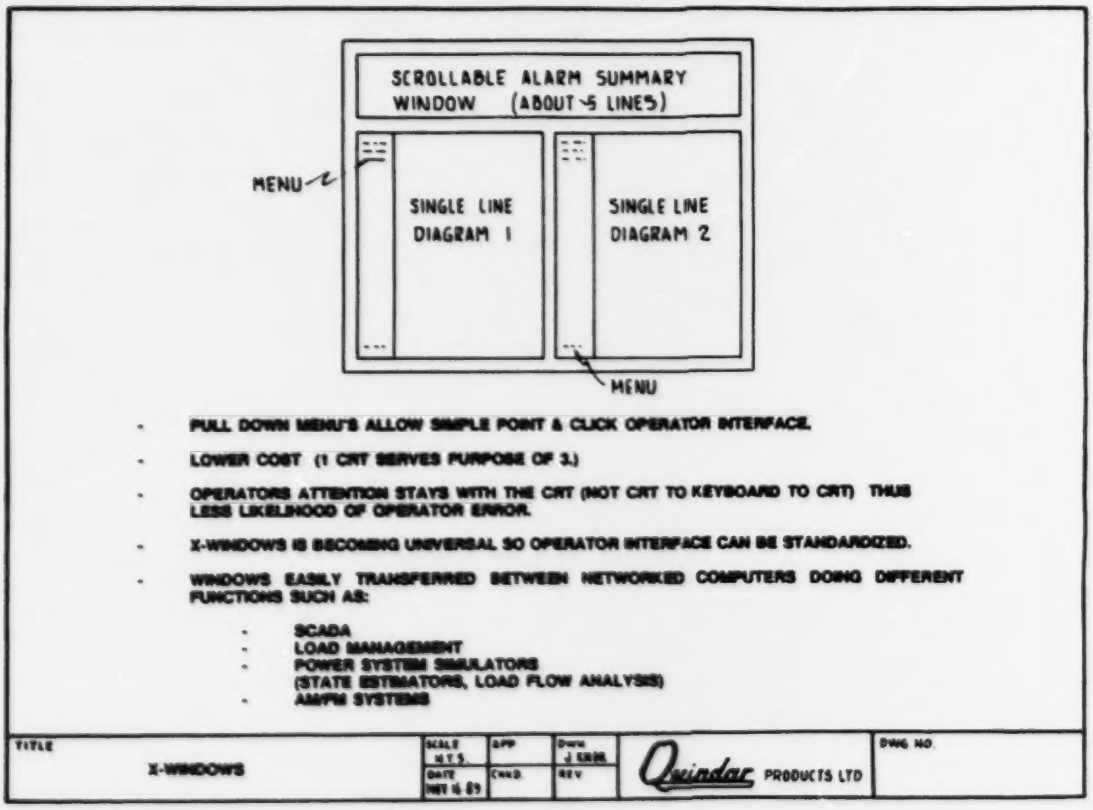

SCROLLABLE ALARM SUMMARY WINDOW (ABOUT 5 LINES)
MENU
SINGLE LINE DIAGRAM 1
SINGLE LINE DIAGRAM 2
MENU
- PULL DOWN MENU'S ALLOW SIMPLE POINT & CLICK OPERATOR INTERFACE.
- LOWER COST (1 CRT SERVES PURPOSE OF 3.)
- OPERATORS ATTENTION STAYS WITH THE CRT (NOT CRT TO KEYBOARD TO CRT) THUS LESS LIKELIHOOD OF OPERATOR ERROR.
- X-WINDOWS IS BECOMING UNIVERSAL SO OPERATOR INTERFACE CAN BE STANDARDIZED.
- WINDOWS EASILY TRANSFERRED BETWEEN NETWORKED COMPUTERS DOING DIFFERENT FUNCTIONS SUCH AS:
- SCADA
- LOAD MANAGEMENT
- POWER SYSTEM SIMULATORS (STATE ESTIMATORS, LOAD FLOW ANALYSIS)
- AM/FM SYSTEMS
TITLE
X-WINDOWS
SCALE N.T.S.
APP
DRWN J. SHAW
DATE NOV 16 89
CHKD
REV
Quindar PRODUCTS LTD
DWG NO.

Figure 2

As Quindar provides both load management systems and SCADA systems, a logical use of increased CPU power is to integrate SCADA and Load Management into a common computer and operator interface. We can still supply both SCADA and Load Management separately, but it is a very low cost enhancement to add the missing capability to either system.

Load Management systems are available as either one way or two way versions. The one way system sends controls to the loads to intermittently turn them off. The load monitoring system (typically SCADA) then monitors the expected load reductions. A typical one way system operating over VHF radio is shown in Figure 3. Note the similarity to Figure 1 as far as the computer hardware requirements.

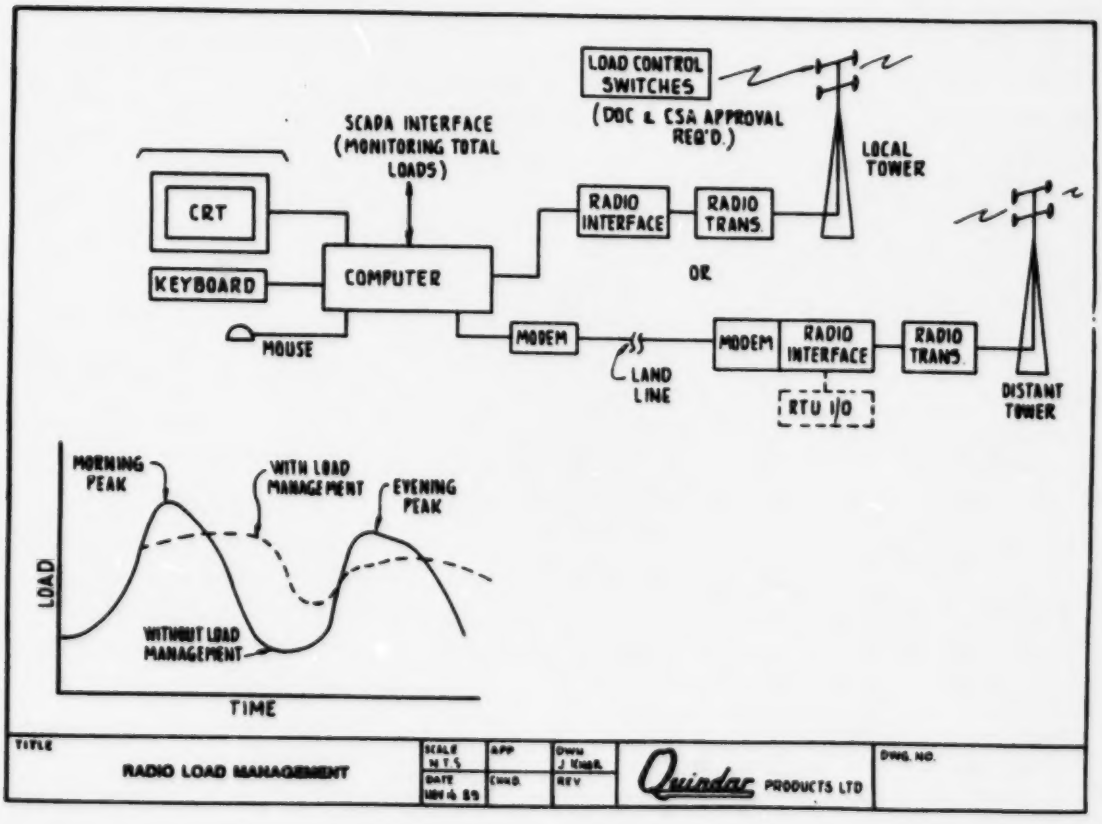


Figure 3

Figure 4 shows alternate one way load management system utilizing a local CATV network as the communications facility to the load control switches. The load control switches rely on inductive coupling of the signal from a section of COAX cable tucked inside the antenna of the Load Control Switch.

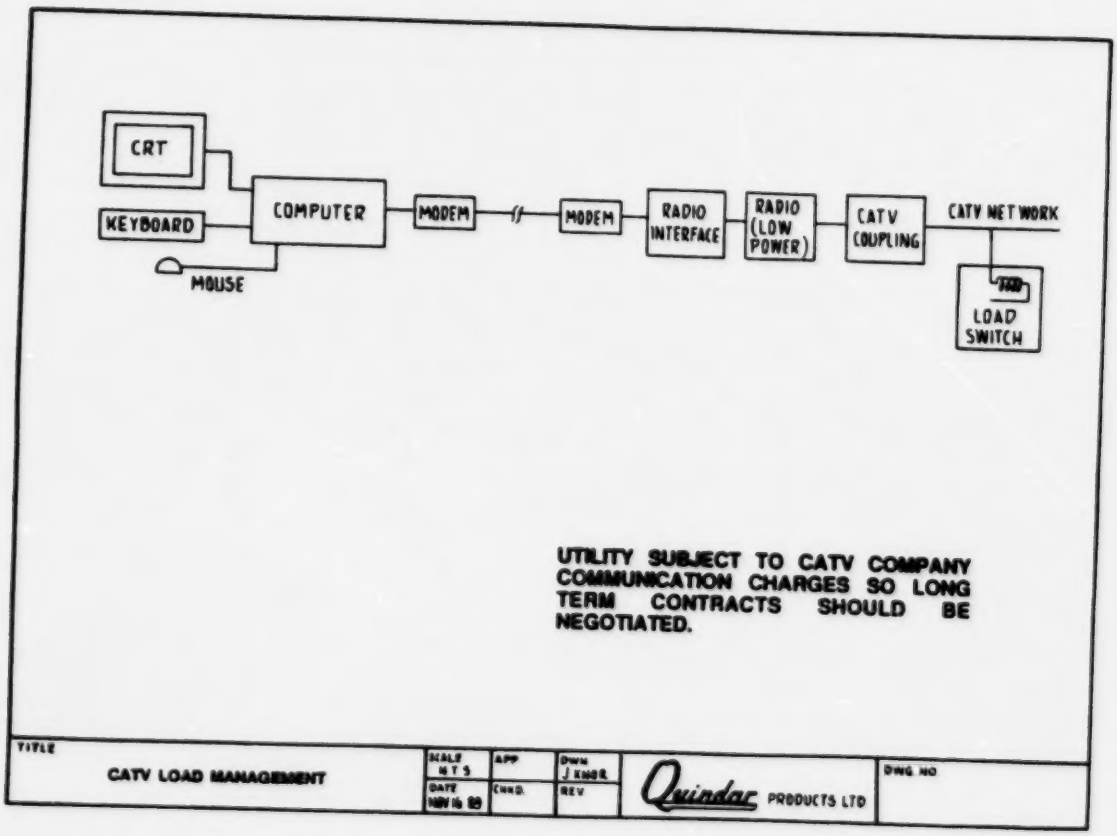


Figure 4

The two way Load Management System (reference Figure 5) provides the added capability of features such as Remote Meter Reading, (with separate Time of Use load intervals), and small low cost sub-RTU's which can be used for monitoring various customer facilities, end of line voltages etc. The two way system offered uses the power network to distribute an injected Power Line Carrier (PLC) communications signal. Note that the two way system requires communications facilities to, and hardware at, the transformer sites. Only I/O hardware has to be added to make this hardware into a SCADA RTU. It is necessary to manually enter, or remotely monitor, the status of the power network pole top switches. Connectivity programmes in the master must automatically keep track of which loads are connected to which transformers as the utility can change the power distribution scheme to cover emergency situations.

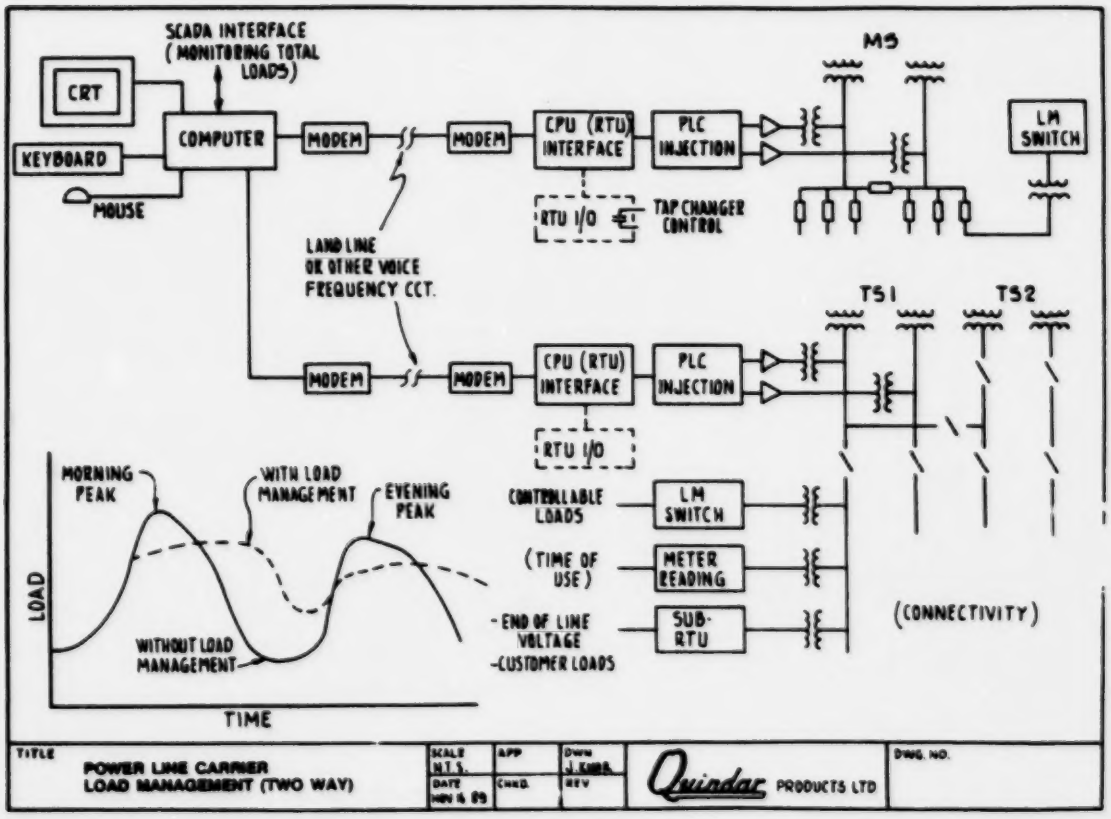


Figure 5

Why integrate SCADA and Load Management? Please refer to Figure 6.

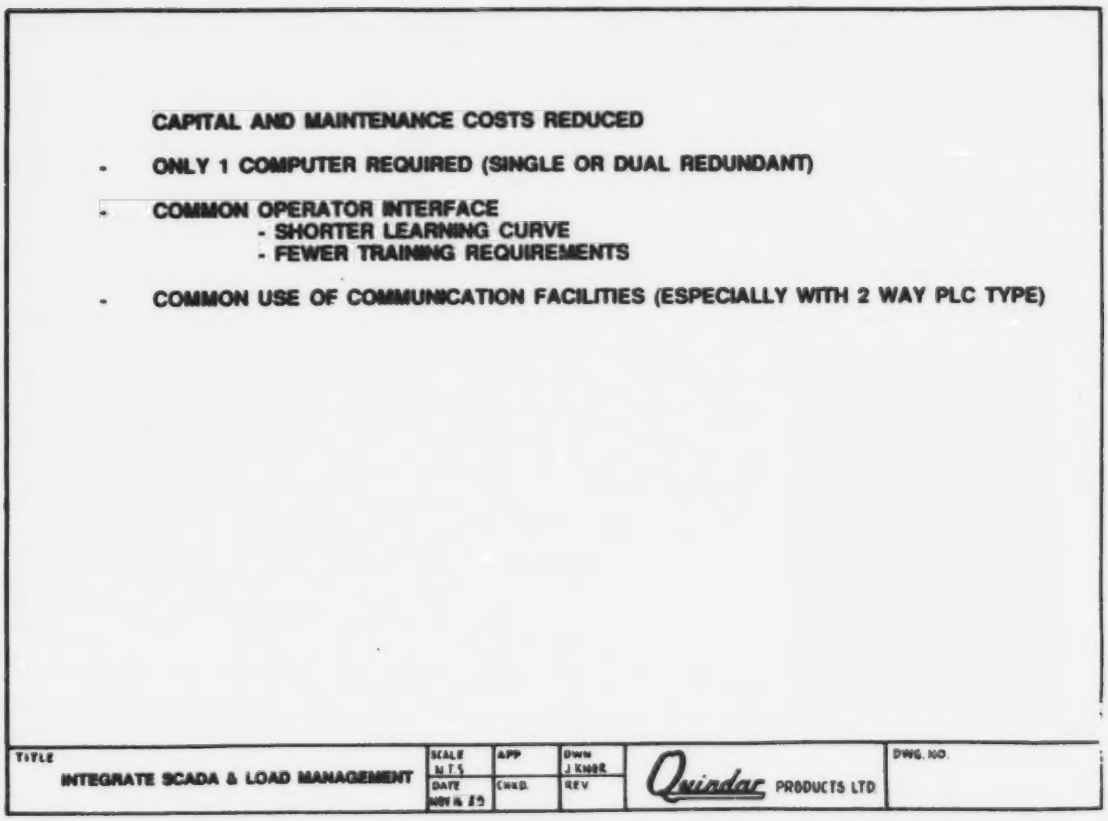


Figure 6

REMARKS BY

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"WATER HEATER LOAD CONTROL - EXPERIENCE WITH POWER LINE CARRIER AND FM/SCA SYSTEMS"

AT

INNOVATIONS IN DISTRIBUTION LOAD MANAGEMENT SEMINAR

SKYLINE AIRPORT HOTEL
TORONTO, ONTARIO

WEDNESDAY, NOVEMBER 29, 1989

WATER HEATER LOAD CONTROL - EXPERIENCE WITH POWER LINE CARRIER AND FM/SCA SYSTEMS

Presented by Steve Anderson
Westinghouse ABB Power T & D Company-Raleigh, NC

Innovations in Distribution Load Management Seminar
November 29, 1989

Load control and other forms of demand side management have been in use for many years in many parts of New England. The range of programs and equipment has varied from older time clock switches for water heaters to switchable time-of-use meters to direct radio systems to ripple and power line carrier in both one-way and two-way formats.

New England, for a variety of reasons, is undergoing a resurgence of interest in load management and related activities. One of the prime reasons for the current level of interest is the fact that New England as a region is experiencing what could become dangerously low levels of generation reserve margins. The ability to directly curtail loads may well become a necessity for many utilities. These programs can range from simply cycling deferrable loads such as water heaters and air conditioners during peak periods to voltage reduction programs (so-called brown-outs) to rotating black outs.

There are other incentives for utilities to implement these programs as well. Public Utility Commissions are demanding that utilities investigate and implement demand side management strategies before they will entertain requests for new generation or rate increases. One local utility is currently involved in a load management program partly because their PUC disallowed a request to build a transmission line to a neighboring utility.

Others who are less immediately pressed are involved simply because it makes good business sense. Many power-purchasing utilities in New England can easily justify load management systems because of the potential reduction in ratchet demand payments to their power suppliers. Nationally, we are seeing trends of smaller users banding together through their G&T cooperative or local municipal group to implement group strategies to control costs and limit demand. One G&T in Florida is actually offering a payment to its members of up to $200 per customer if the local cooperative will install load control that the G&T can cycle when necessary. This can easily pay for the system and the co-op can use the hardware for whatever additional programs they wish.

There are still the issues of whether programs should be voluntary or direct. Time-of-use rates are by definition an attempt to force usage changes through economic incentives. TOU programs tend to vary wildly in their implementation with some being

doomed to failure because the economics are so unfavorable to the user. Other utilities have found that customers who volunteer for TOU rates tend to be those who would use electricity during off-peak periods normally, thus yielding little if any load shift. As a manufacturer of both types of equipment, TOU meters as well as load management systems, you may well think we are optimally positioned to benefit in either instance. The reality is that, no matter what we introduce as products, we are hard-pressed to respond to all of the schemes which utility marketing and PUC personnel can envision or would like to implement.

The situation today is not really as chaotic as it may seem. There are numerous mature products and systems available to utility planners for demand side management programs. On the metering side, we at WABB are now into second and third generations of electronic TOU and demand registers. These are modular, more functional, and less expensive than past units, which is just what you would expect of high volume electronic devices. Similar devices are available from most major meter manufacturers and we are actually moving toward more common programmability. At WABB, these registers are now being married to a new family of all electronic solid state meters in both KWH and KVA formats.

One of the casualties of all this electronic warfare is that the old mechanical time clock switch is going the way of the buggy whip. Many devices are no longer manufactured and utilities are having to cannibalize parts to keep them running. More importantly, we tend to think that the time clock as a concept will phase itself out for reasons of functionality. First, time clocks get easily out of synch whenever power outages occur and the expense of site visits to reset them is considerable. Secondly, while they were designed to shift loads on a daily basis, they may not really help overall utility load factors and revenues. Most contemporary load management systems really only need to operate for limited periods of time during yearly system peaks to be effective, thus minimizing customer inconvenience. Even in these instances, load factors are improved and revenue is rarely lost as kW-hours are usually shifted to off-peak periods. Systems offering dynamic control can however be employed when needed for other uses such as feeder load balancing or generation replacement.

On the direct load management side, utilities today have a wide choice of both one and two-way communication systems. The most common systems in usage are one-way VHF radio systems which operate in the 150 to 170 MHz band. These have been in use for about 20 years, with several old line suppliers like Motorola dropping out and several new suppliers stepping in to fill the void. The early systems used limited tone groups for addressing, which led to some interference among neighboring utilities. Newer systems now utilize digital addressing schemes to offer greater addressing flexibility for load groups. The major drawback of VHF systems is the limited availability of channels,

particularly in crowded urban areas like the northeast. To alleviate some of these problems, the FCC has authorized a number of splinter frequencies for utility usage. The use of these has, however, caused interference with existing systems in certain instances. Also, VHF systems are limited to 50 watt transmitters and signal propagation tends to be line of sight. For a larger utility, this means they will probably need multiple transmitters to blanket the system and even then the typical coverage is about 90%. This means that one can expect to lose the benefits of up to 10% of the units installed or, conversely, that you may have to buy and install 10% more units than a more reliable communication medium may offer.

To overcome several of these objections, WABB has developed a one-way radio system which employs the Subsidiary Carrier of commercial FM radio stations. the SCA channel was originally used for MUZAK transmissions and lately has been used for a number of applications including paging. WABB in fact has the patent for the use of this system for automated distribution and load management applications. FM/SCA offers significantly better coverage in a given service area over VHF due to its larger available transmitters, better building penetration and higher data rates. System installations have verified typical coverages in the 95-98% or better region. FM/SCA's installed transmitter costs are thus lower and the utility is not required to obtain an FCC license. With FM, multipathing problems do occur but the use of a signal strength meter during installation can often eliminate these effects by simply moving the receiver a few inches.

WABB engineers have taken advantage of a microprocessor-based load management receiver and built in a number of significant new features. First, they built in a scanning receiver which allows utilities to change radio stations or frequencies at will. The unit is designed to listen for a test signal and locks onto a given frequency. If the system changes frequency, the receiver will hunt for the new test tone and lock onto the new signal in a few seconds.

The remote devices were given a very flexible addressing capability which includes a unique I.D. and up to four group addresses with several hundred possible addresses in each. Significantly, these block addresses which are used to implement load control strategies can be reprogrammed at will from the central computer. This allows load groups to be sized up or down depending on experience without ever having to visit the site.

Because the device has a unique digital I.D. as well, the load control receiver can be remotely deactivated or activated, as required. One of our major users has told us this has saved him thousands of dollars in un-necessary service calls. If a customer complains about being out of hot water, the dispatcher can

deactivate the unit and restore the load relays to their normal position. If the customer is still out in an hour or two, a service technician can then be dispatched to see if there is a receiver malfunction.

The microprocessor helps in other areas as well. In older one-way systems, the normal approach is to build up load control schedules on the master station and then implement various load strategies by sending out multiple commands from the Master. In the FM/SCA receiver we can simply transmit a selectable load cycling command. The remote will then automatically cycle the load on and off to give anywhere from a 5 to 100% duty cycle for up to eight hours.

The micro is also used to generate a random restoration period to prevent groups of receivers from restoring simultaneously and spiking the demand up. Another standard feature is cold-load pick-up in which the device senses a power outage and, upon restoration, will automatically shed its attached loads for a short period and then randomly restore them. This feature can greatly reduce the inrush on a cold feeder which in the past often caused additional reclosures or breaker trips.

One common complaint about one-way systems is that there is no reliable way to verify operation over time. In the past, mechanical counters were used to register operations which could be read and correlated with a master accounting of commands. Unfortunately, mechanical counters are notoriously unreliable. The micro again has come to our rescue by allowing us to store a variety of data, including operational counts, power outages, etc. This data can be read out locally using a palm-size service wand which gets its information from the remote through the same LEDs we use to indicate local load status.

The point of all this is just to give you a feel for what can be done to modernize a one-way radio system using state-of-the-art design and components.

Other one-way options include low frequency ripple injection systems, several of which were installed about 10 years ago here in New England. Ripple generally is quite slow (around 2 baud) and requires sizable injectors to function. It can, however, be cost competitive when injection can be implemented at subtransmission levels such as 46, 69, or 115 kV to give broad coverage. WABB inherited the original Brown Boveri ripple system and has modernized its receivers using the same microprocessor technology described previously for FM/SCA. Micros have also allowed us to emulate virtually any ripple protocol in the world with one receiver, thus the new remotes can be used to upgrade the functionality of any existing system.

The greatest functionality will be achieved, however, through the use of a two-way communication system. Ten years ago, EPRI

funded the installation of five promising new technologies: three of these were based on power line carrier, one was a telephone based system, and one used 900 MHz radio. Of the group, only distribution line carrier has evolved into a viable commercial system. As is typical of emerging technologies, a few of the suppliers are gone, some are inactive, and some of the systems proved unworkable. Again, several new manufacturers have moved in to fill the void so buyers today have several competing systems to chose from in power line carrier.

The current WABB EMETCON system is a direct descendant of those early EPRI trials and over 20 years of research. The system went into active commercial production in 1983. Since that time we have put over 100 systems into commercial operation, providing load control, remote metering, load survey, and a variety of distribution automation functions such as capacitor control, voltage control, and outage indication.

The system consists of a central computer system, either IBM PC or DEC VAX based, which communicates over bulk channels such as telephone or radio with carrier injectors located in the distribution substations. From the substation, communications are sent via distribution line carrier to remotes located at load points and meters. Both one-way and two-way terminals are used, depending on the application.

One-way devices are typically used for load control, feature a two level group addressing scheme, and offer similar random restoration timers and cold load pick-up features like those previously mentioned. Again, microprocessors are used to provide distributed intelligence and to maximize the speed of the communication channel, typically around 76 baud.

Two-way devices are either Meter and Control Transponders which are normally built into a conventional meter or Distribution Control Terminals which are designed for line applications. MCTs typically record pulses and allow the meter KWHs to be read remotely, while specialized devices are provided to perform remote time-of-use metering, demand metering, or load survey of kW data. Optional load control outputs allow the MCT to perform load control like the one-way device and also to remotely monitor status of the loads. Given recent efforts to cost reduce the MCT into the $150-200 range, it may soon be cheaper to implement TOU metering remotely rather than through the stand-alone meter mentioned earlier. The EMETCON TOU meter also offers the ability to be reprogrammed remotely via carrier so TOU strategies can be changed at any time without having to visit the device.

The distribution terminal, the DCT, is designed to remotely control a switch or capacitor bank and features up to four analog inputs to remotely monitor such data as volts, amps, or temperature.

In recent years, the trend is towards a higher level of integration of the two way systems with either distribution SCADA or corporate Energy Management Systems. One of our largest systems supplied will be shipped to Old Dominion in Virginia at the end of this year. In this system a central coordinating computer will monitor generation and weather, produce a system-wide load forecast, and create specific load control strategies for up to nine member cooperative systems. Each co-op will have its own integrated SCADA-EMETCON system for load control, meter reading, line monitoring, and distribution substation SCADA. A similar system will be supplied for the complete Central Maine Power system.

we are already looking beyond the integrated system, however. In the near future we see a definite need for load management and automated distribution systems to interact on a network basis with corporate C.I.S. systems and other "islands of automation" within utilities. Automated Mapping and Facilities Management Systems are beginning to be implemented and we already see a need to utilize this data as part of our operator interface for an automated distribution system. We are also seeing new software packages becoming available in the near future which use artificial intelligence to provide options for distribution feeder reconfiguration and outage restoration and many other functions on a real-time basis. We are already developing the strategies and software to allow us to move load management into the twenty-first century.

In short, we see a whole variety of new products and systems which are now available for utilities to use in addressing their needs in the areas of load management, demand-side strategies such as TOU metering, and automated distribution. As an industry, we have the benefit of experience and the skills to carry these systems forward as we move into a new decade. The choices may be tough as you work to develop the programs which are appropriate to your utilities, but you can at least be thankful that you will have the technical means to implement them.

REMARKS BY

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"INCREASING ENVIRONMENTAL AND ECONOMIC CONSIDERATIONS FOR LOAD MANAGEMENT"

AT

INNOVATIONS IN DISTRIBUTION LOAD MANAGEMENT SEMINAR

SKYLINE AIRPORT HOTEL
TORONTO, ONTARIO

WEDNESDAY, NOVEMBER 29, 1989

"INCREASING ENVIRONMENTAL AND ECONOMIC CONSIDERATIONS FOR LOAD MANAGEMENT"

Remarks of

Larry Mansueti, Staff Engineer
AMERICAN PUBLIC POWER ASSOCIATION
at the
Innovations in Distribution Load Management Seminar
Ontario Ministry of Energy
Toronto, Ontario

November 29, 1989

There is a saying that goes: "When the only tool you have is a hammer, every problem looks like a nail."

That saying applied to the electric utility industry of a decade ago: "When the only tool you have is a generating unit, every problem looks like power supply."

For the three decades after World War II, the simple answer to satisfying consumer demand for an adequate, reliable supply of electricity at a reasonable price was the building of a new power plant. Generating units steadily increased in size and each tended to produce power at a unit cost below that of its predecessor. Economies of scale and declining unit costs for electricity were the cornerstones of that time period.

But sixteen years ago, the Arab oil embargo marked the beginning of a startling change in the electric utility industry.

As the declining unit cost of electricity began to bottom out in the late 1960's, power bills ballooned in the 1970's under the heavy impact of rapidly rising fuel prices, along with steady inflation of construction costs,

continued expansion of environmental protection requirements, and delays in construction of new power plants and transmission lines due to persistent public opposition. While fuel prices are no longer rapidly rising as they were a decade ago, the other legacies of the Arab oil embargo are still pretty much with us.

Growing in influence since the early 1970's, the environment is poised to become the "oil embargo" of the 1990's. Acid rain, nuclear waste, hazardous waste, water pollution, electric and magnetic fields, and global warming -- these labels tag issues that increasingly become the prime factor governing electric utility decisions.

Public opinion polls tell us the importance the public places on the environment. That concern is bound to increase, not decline. Those of you from utilities involved in trying to site and build a new power plant or transmission line and facing opposition from various groups don't need polls to tell you of the importance of the environmental issue.

In the U.S., expect to see proposed acid rain legislation, likely to become law next year, to perhaps be <u>the</u> key determinant of what type and how much of new generating capacity is built in the 1990's. With the proposed emissions cap of the Bush bill, many predict that demand side management, including load management, will take off in the U.S. as fossil-fueled generation will ultimately be severely restricted by an emissions cap. The outlook for traditional coal-fired generation looks bleak. Similar pressures due to acid rain programs are already occurring here in Canada.

Though the answers aren't in yet from the scientists, evidence increasingly points to global warming as a likely result of our combustion of fossil fuels.

Should the predicted global warming occur, dramatic changes in the world's climate will occur. While Canada's northern areas will become suited for farming, existing prime farmland in more southern climes will turn to desert. Coastal areas will exercise greater flooding. Dramatic shifts in electric comsumption will impact electric utilities.

The generation of electricity is a major source of the greenhouse gases that supposedly cause global warming. In the U.S., about a third of greenhouse-causing CO2 comes from the production of electricity. In Canada, the contribution from electric generation is probably similar.

Though electricity production does not contribute to global warming in the same high proportion as it does to acid rain, there will undoubtedly be calls for electricity to play a major role in slowing the rate of global warming.

Greater reliance on nuclear power is one way to limit CO2 from electric production. However, public opposition, especially in the U.S., limits the nuclear option. Switching to natural gas-fired combustion turbines is possible, but very costly for base-load generation. Scrubbing CO2 from coal plants is prohibitively expensive. Renewable technologies are maturing and can make some contribution.

But the most cost-effective option is to increase energy efficiency through measures such as more efficient lighting, industrial motors, and appliances.

Estimates by the American Council for an Energy Efficient Economy (ACEEE) project that between 35% and 40% of U.S. electricity could be saved at a cost of three cents(U.S.)/kWh or less. Electric motors can be made at least 40% more efficient and refrigerators 75% more efficient, while available lighting technology can cut lighting's electricity use by as much as 75%, according to ACEEE estimates.

Demand side options such as load management obviously will have a role in improving energy efficiency.

What the economic pressures since the Arab oil embargo, together with today's increasing environmental pressures, create for the electric utility industry is uncertainty -- uncertainty about the trend of load growth, uncertainty about how to meet whatever demand develops, uncertainty about what it will cost to do the job.

What can electric utilities do about uncertainty?

Hedge their bets. Spread risks. If feasible, share large projects with other utilities. Pace expansion close to load growth. Shop for bargains -- including special sales of surplus electricity now available in many areas. Employ low capital, short-lead time projects when appropriate. Invest in cost-effective solutions which don't put you out on a limb. Take small bites. Seek flexibility and diversity by developing and using options.

One of the best ways to do low-capital, short lead-time projects and gain flexibility and diversity is to use demand side options like load management.

As we are finding out today at this conference, demand side options are usually cheaper these days than those on the supply side. The Washington, DC-based Potomac Edison Power Company is embarking on a demand side management program since the cost is 15% to 40% cheaper than building peaking capacity to meet the same demand. Load management is a key feature of their new program.

And since demand side options increase energy efficiency, we help ensure environmental protection and economic well being at the same time -- two national objectives that often are difficult to bring together.

A utility's goal is to provide an adequate and reliable supply of needed electricity at the lowest possible cost consistent with proper protection of the environment. Load management is a tool to reach that goal. Demand-side programs, which deliberately modify load shapes, offer utilities a flexible strategy for operating efficiently and effectively in uncertain and competitive environments.

At the same time that economic and environmental pressures force us to increasingly turn to demand-side options, we are fortunate to be blessed with many favorable changes in technology.

As the cost of kilowatt of central station electric plant has risen, the cost of silicon chip has fallen; sophisticated energy management controls today are cheap compared to a decade or so ago.

We are truly fortunate to have the technology maturing just about when we need to use it.

Small organizations couldn't even consider load management a decade ago. Now cheap PC-based load management systems are available for even the smallest of organizations. Less bureaucracy at smaller organizations makes load management often easier to implement than at larger organizations -- be they electric utilities or electric customers.

Load management -- the effort to influence end use of electricity to reshape a utility's load profile -- is today an essential part of demand side management. Whether it is direct, distributed, or local control, whether it involves off-peak heating or cooling, whether it aims straight at duel-fuel furnaces or uses thermal storage, load management can play a significant role in keeping costs down for both the utility and customer as well as keeping the environment happy. Whether it is to reduce peak-period demand, move electric use to a different time, or increase off-peak energy sales, load management can aid cost cutting.

What are some actual experiences with load management?

"In a month or two I'll be able to tell you exactly what my winter peak will be," Dick de Grasse, former general manager of the Stowe (Vermont) Electric Department has said, "I'll know, because I'll set it".

Stowe's largest customer, the Mount Mansfield Co., monitors system demand and adjusts snow-making operations to fit peak negotiated well in advance. Demand rates and demand controllers are mandatory for electric heat customers in Stowe, and thermal storage is encouraged.

North Attelboro (Mass.) Electric Department has used mandatory load management since 1977. Its winter peak is now about equal to the summer peak; the municipal controls about 1.5 MW of the 25 MW winter peak.

North Attelboro identified electric water heaters as the primary target for load management, and controls 98 percent of the water tanks in its territory. Other loads under direct control are: commercial/industrial central air conditioning, an offpeak heating storage system and an all-electric high school. Of the eight schools in the community, the all-electric high school with load control has the lowest energy cost on a per-square foot basis. The other seven all use fuel oil. Uncontrolled, the high school would add 500 plus kilowatts to the winter peak. The load control system is tied into the school's own load management system.

During this conference, you will hear about the experience of two other municipal electric systems--Cornwall (Ontairo) Electric and the Massena (New York) Electric System--who have used load management to improve the efficiency of their operations.

It sounds like load management is very advantageous to electric utilities. But what about electric customers? In the short-term, well-designed load management programs should allow electric bills to decline or at least not increase for those participating in a load management program. Rate structures may need to be adjusted. Utilities and their customers need to work together to design load management programs that are equitable to both.

In the long term, electric customers benefit by helping their electric

utility avoid or delay the need to build costly new generating capacity or purchase additional peak power.

Keeping the cost of power down helps the national economy. It is counter-inflationary because it offsets high interest rates for business, decreases production costs, and encourages use of new technology--a win-win situation for all.

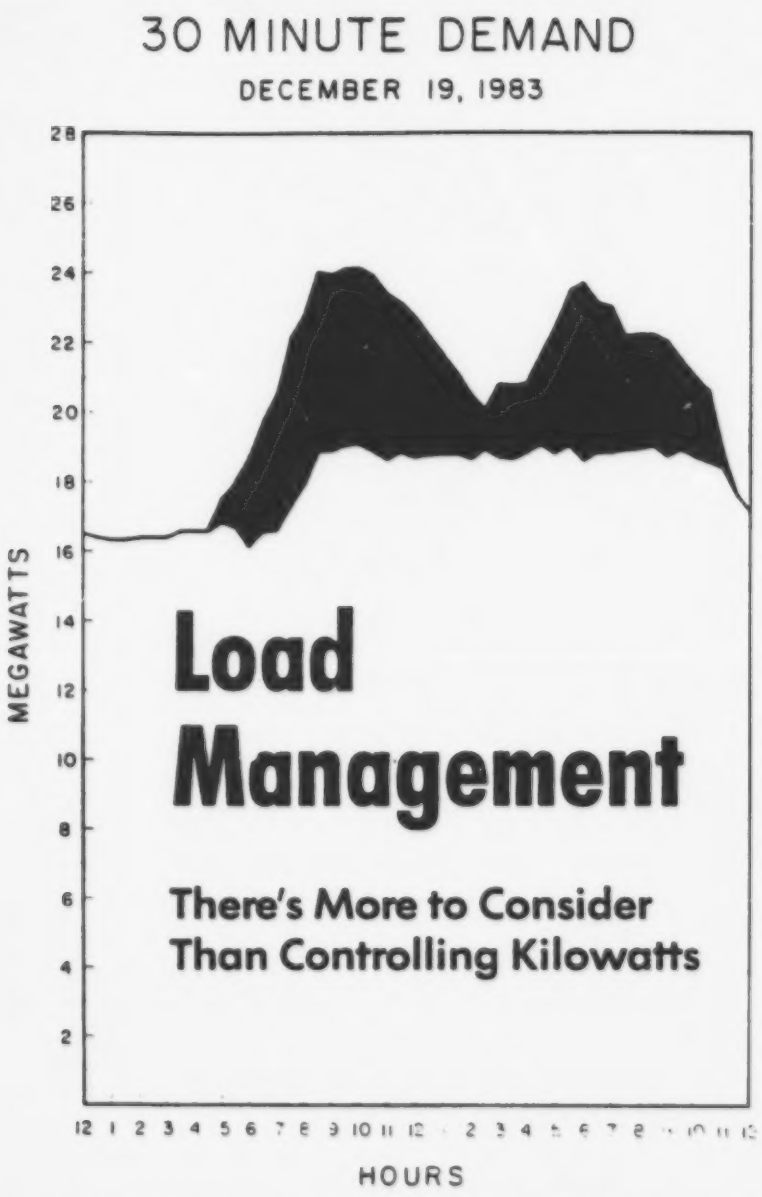
Yes, there are problems in using both the technique and the technology of load management. Data on actual experience is skimpy. Adequate analytic approaches have not been fully developed. Equipment unreliability is too high and availability too low. Ability to predict costs and benefits is not 100%. Acceptability by customers is not certain. But these problems were more prevalent five years ago and are rapidly diminishing. There is today an expanding experience base that tells us that load management does work. Attached is an article from Public Power magazine that relates many of those experiences.

On the other hand, there are clear advantages to load management. It is flexible in adaptation, permits testing through comparatively inexpensive pilot projects, and can be introduced in small increments tailored to meet particular problems. It allows consumers to make choices by "unbundling" the package of firm requirements sales which is the more traditional offering by utilities. It has a short lead time, exhibits immediate results, and may provide a fast pay-back. It is a way of beating market/regulatory risk which jeopardizes other investments. Helping lower a customer's electric bill can be the needed difference to stay in business and remain competitive. In extreme cases, a

business can be prevented for moving or shutting down. It is a means to enhance load factor and wring more out of the system electrically and economically.

Perhaps just as important as the economic benefits, load management has the advantage of forcing you to get to know your operations well if you are an electric customer and for you to get to know your customers better if you are an electric utility.

Today there are more choices for both electric utilities and their customers to make, and there is no best answer; Each must custom tailor its response, guided by standards of efficiency, effectiveness, and equity. Electric utilities and their customers must work together to develop workable solutions satisfactory to all. But by sharing knowledge with each other, we can compare the marginal utility of various solutions and avoid "reinventing the wheel". Thats what this seminar is all about.



The chart shows what Valley City (N.D.) Municipal Utilities' peak demand would have been without load management. The red shows what the load would have been without voltage control and the green shows the demand without controlling dual-fuel space heaters and water heaters. The bottom line is the actual peak demand. Photo courtesy Valley City Municipal Utilities

by **LORI A. WOEHRLE** *assistant editor, PUBLIC POWER*

SIOUX FALLS, S.D.

BY CONTROLLING DEMAND for electricity to avoid system peaks and valleys, load management saves money for both utilities and their customers. Who can question its value?

But even load management has two, or more, sides. The Missouri Basin Municipal Power Agency, a joint-action agency whose members are in Minnesota, Iowa and the Dakotas, held a seminar here in April to examine the issue.

"It's not a black and white situation," said Missouri Basin General Manager Russell Dau during the seminar's opening address. "The important thing as far as policymakers are concerned is that you look at both sides of the picture.

"We're all interested in working toward a least-cost strategy—the energy services concept," Dau told about 150 public power officials. "We're all looking for the best possible use of local resources.

"But people buying and installing load-management systems to experience immediate and vast reductions in their wholesale power bill are going to be disappointed," he said.

In the case of Missouri Basin, 75 percent of the agency's expenses will remain constant, Dau said. About half the costs are debt-service related and 25 percent are other fixed costs. Therefore, if the agency sells fewer units of electricity the rate for units sold may increase.

Another concern is reliability of equipment. As one speaker put it: load-management systems do not run themselves once installed. A missed opportunity for shaving a peak because of an equipment failure can cut expected savings in a hurry.

"Some utilities appear to be getting involved with load management for the wrong reasons," Dau said. "There are other benefits to load management besides reducing wholesale power costs, such as getting the best possible efficiency out of the system." Quantifying those benefits can be difficult, Dau noted.

Alton
Improved Load Factor

The 510-meter municipal electric utility in Alton, Iowa, became interested in load management in part because the system's load was decreasing as its peak was climbing, causing the utility's load factor to drop, said Curt Punt, Alton public works director.

Coupled with the decreasing load factor was the cost of power for the utility, which purchases all its electricity wholesale from Western Area Power Administration (WAPA) and Missouri Basin. While the system's blended cost of power, 13.4 mills per kWh in 1979, about matched Missouri Basin predictions, "the costs concerned us," said Punt.

"But a larger concern was created when we took a look at what power costs other agency members had," he said. "Sixty-five percent of agency members were receiving blended power for less than we were." The utility determined two reasons for the difference. First, Alton purchased more of its power from Missouri Basin than did many other agency members, and less from WAPA, which has less expensive electricity.

Worthington, Minn., police dispatcher Shauna Davis, receiving notice that the system is nearing a peak, will alert utility officials.

Michael Raverty, Worthington water superintendent, controls wells and water-pumping stations to reduce electrical demand. Photos courtesy Worthington Public Utilities

Second, Alton's load factor was lower than that of other members.

A third reason for looking at load management related to system improvements, Punt said. The utility was postponing some system uprating until revenues increased under an improved load factor. "We were afraid we would not get the revenue needed to pay for those improvements," he said. "We needed to use more of the system more of the time."

The utility's feasibility study enumerated the load available for control, including central and window air conditioners and electric water and space heaters. The study found that 92 percent of residential customers would participate in load management.

In July 1981 Alton installed a hybrid system, which uses a radio signal from equipment at the utility to receiver-transmitters on the secondary circuit. The receiver-transmitters send the signal on the power line to controllers on home appliances. The system cuts off the appliances for 7.5 minutes of every 30 minutes during a utility peak.

The system cost $44,000, or $246 per controlled appliance, and is installed on 77 percent of the central air conditioners and 69 percent of the electric water heaters in the utility's service area. System operation and maintenance cost about $3,000 annually.

The utility has installed an indicator in the office of its largest commercial customer, representing nearly 25 percent of the system's load. The indicator warns the customer about 15 minutes before the utility is about to reach a peak. The customer can voluntarily drop load.

As a result of the load-management program, the utility can shed about 60 kW to 100 kW of load during the winter and about 200 kW during the summer, Punt said. "It has worked out quite well for us," he added.

The system's load factor improved from about 55 percent to 57 percent after six months of operating the load-management program. By 1983 the load factor was 63 percent. Punt attributes about 4 percent of the increase to load management.

'Alton needed to use more of the system more of the time.'

Alton saved about $24,000, or 16.6 percent of its power bill in 1982, and about $33,000 in 1983. The percentage of the savings stayed constant but the amount of money saved increased as power costs climbed.

Longmont Lost Revenue

The residential load-management program in Longmont, Colo., was created in response to an unpopular rate structure that included a demand rate, according to Laura Belsten, Longmont energy services coordinator. All-electric homes are now subject to the demand rate, $6.19 per kW. Customers under the demand rate pay less for electricity used, 1.7 cents per kWh *vs.* 5.2 cents per kWh for other residential users.

Longmont buys 70 percent of its wholesale power from WAPA, with the remainder supplied by Platte River Power Authority, Fort Collins, Colo. Longmont serves 20,000 meters, of which 88 percent are residential customers. About 900, or 5 percent, of Longmont residential customers live in all-electric homes.

In November 1982, after consulting with local appliance merchants and electricians, Longmont purchased 100 demand-control devices and made them available to customers at a wholesale price. The utility later purchased another 50 controllers. Customers can pay for the controllers at once or over one year—without a finance charge—through the utility bill. While the utility does not install the devices, it provides names of local electricians who have been trained to install them.

The customer determines a level of demand and sets the device, which is attached to the home's electrical circuits. When demand begins to reach the chosen level, the controller cuts off power to major appliances according to a priority determined by the customer. The standard priority is space

'The average all-electric customer using the controller is saving between $150 and $300 annually.'

heater, water heater, then dryer; Longmont does not have a high air-conditioning load.

Longmont publicized the control program through workshops, advertisements in local media, and direct mail to customers explaining the program and its availability.

The average all-electric customer using the controller is saving between $150 and $300 annually, Belsten said. Customers are generally lowering demand by two kW to four kW per month in summer and from five kW to six kW in winter, she said.

While cautioning that results are preliminary, Belsten said the utility lost about $30,000 in revenues in the first year of the program. The system's peak was cut by less than 1 kW per customer, not enough to pay for the program and compensate for reduced revenues, she said, adding that in the future the utility's rates might be forced up by the revenue shortfall.

"It really depends what value you place on public relations," she said. "In terms of education the program has been tremendous. There could be other things we could be spending our money on; for example, some other utilities are helping the Salvation Army" assist low-income customers in paying utility bills, she said.

Good Relations Justify Program

Moorhead (Minn.) Public Service Department was faced with rapid growth in its electric load in the 1970s, in part because use of electric space heating increased after prices for oil and natural gas skyrocketed, said Thomas Heller, electrical engineer for the utility. Also, in 1976 a large brewery located in the city.

The utility buys its power wholesale from WAPA and Missouri Basin. The increased load was causing Moorhead to buy more power from the joint-action agency, which pushed its wholesale power bills up, Heller said. Rising power costs lead the utility to hike rates in 1977 and to begin looking hard at load management.

Moorhead first started a voltage reduction program, under which the usual 122-V level at substations was automatically reduced to 116 V during peaks, allowing for a 114-V level at points of service, Heller said. A SCADA (supervisory control and data acquisition) system purchased in 1980 controlled voltage levels.

The following year the utility surveyed customers on a dual-heating program. Consumers would pay a lower rate—a 2.6-cents-per-kWh flat rate compared to 3.2 cents per kWh for the first 1,400 kWh and 5.2 cents per kWh for additional kilowatt-hours—for installing space heaters capable of switching

'The main reason (Moorhead) went to load management initially was to save money . . . Even with no money saved, we would have offered load management based on the community support for it.'

to a fuel other than electricity. About 400 customers returned positive responses, "more than enough to justify the program," Heller said.

Moorhead upgraded its SCADA system to enable it to use radio signals to switch dual-fuel heaters automatically to the alternate fuel.

Under the program, aimed primarily at customers using forced-air oil heating, the utility offers up to $2,000 in loans with a 5 percent interest rate, payable in five years, to purchase and install dual-fuel heaters. About 100 residential and 10 commercial customers participate in the program.

The utility is shaving its peak because about 40 percent of those participating were electric heating customers who now switch when the load is heavy. The remaining 60 percent, formerly oil- or gas-heating customers, are filling the load valleys, yet not adding to the system peak, according to Heller. The utility's load factor has improved from the 80 percent range to more than 90 percent last winter on the peak day.

"The main reason we went to load management initially was to save money," said Heller. "But more important now is the public relations aspect. Even with no money saved, we would have offered load management based on community support for it."

Consumer Cooperation Crucial

Worthington (Minn.) Public Utilities, a summer-peaking system which serves 5,000 meters, got involved in load management for several reasons, according to City Administrator Don Habicht. The utility stopped generating electricity about three years ago and began seeing its demand charges increase as its load factor dropped.

Under the program, just before summer the utility places advertisements in local media to familiarize customers with what a peak is and how to avoid it. A device at the utility sounds an alarm at the police station when the load nears the system peak. The police dispatcher calls utility officials, who call the local radio station.

The radio station plays prerecorded "peak-alert" announcements that ask customers to turn up thermostats on air conditioners and avoid using major appliances during potential peak times. The utility also asks major industrial customers to reduce usage. Large commercial customers, such as stores in large shopping malls, are asked to reduce lighting and are issued posters that explain why the lights are dim.

Also, the city will reduce pumping at the municipal water plant if possible and will reduce voltage to 123.5 V at substations and 112 V at the customer service point.

The utility is saving from $20,000 to $30,000 per month by relying more on its less-expensive WAPA allocation, according to Habicht. Last year, Worthington bought 55.3 percent of its supply from WAPA, up from 49.8 percent in 1981.

Worthington prefers its program over automatic load-management systems requiring hardware because the voluntary program needed little investment by the city and because the system's peak is so short a more extensive system was not necessary, Habicht said. The program qualifies as an energy conservation program under WAPA's requirements for preference customers and has improved customer awareness of electrical energy and the utility, he said.

Disadvantages are that the program temporarily removes utility personnel from their usual duties and is difficult to communicate to customers; participation drops during prolonged periods of hot weather; and good cooperation with local media is needed for it to be successful, Habicht said.

Ortonville Consumers Respond

Ortonville (Minn.) Water and Light Department, serving 1,350 meters, had been a summer-peaking utility until about 1978, when increasing oil prices convinced many consumers to convert to electric heating, according to City Clerk Don Geier. Electricity looked particularly attractive because the city purchased its power from WAPA, which

Load Management Options for Small Utilities

LOAD MANAGEMENT FOR SMALL utilities will be the subject of a workshop Sept. 11-12 sponsored by the APPA-Western Area Power Administration Energy Services Exchange (ESE) program. Missouri Basin Municipal Power Agency will be a cosponsor, as will the Nebraska Municipal Power Pool. The workshop will be held in Lincoln, Neb., with a site visit to Wahoo, Neb., to inspect a Westinghouse Corp. two-way load management system. For details call Karen Anderson or Jacquie Cochran at APPA on ESE's toll-free number, 800/824-5424.

allowed it to keep rates down. But as the load increased, Ortonville added increasing amounts of supplemental power not as inexpensive as WAPA electricity, and the utility faced rate hikes.

In 1981 the city installed a $250,000 radio signal load-management system that controls 1,300 water heaters (representing 98 percent of all water heaters), 270 central air conditioners, 45 dual-fuel space heaters, two large city pumps and the utility's voltage level. The system allows the city to manage 1,500 kW in the winter and 600 kW to 700 kW in the summer, Geier said.

He said the utility has had "exceptional acceptance" by consumers of the load-management system and "very few complaints." The system has paid for itself in its two-and-one-half years of operation and the utility has been able to purchase a backup computer for it, Geier said.

Ortonville consumers with dual-fuel heaters have a rate incentive to switch to that type of heating system. The standard winter residential rate is 4.0 cents per kWh for the first 1,500 kWh, and 4.7 cents per kWh for additional usage, compared to 3.2 cents per kWh for all electricity used by those with dual-heating.

The utility also launched a major public information campaign to elicit customer cooperation. The campaign began with a letter to all customers, followed by advertising in the local media which was coupled with front-page news stories on the system, and a consumer information display booth that appeared at shopping malls and other areas where the public gathered.

The campaign paid off last December when the load-management system failed about six hours before a major cold snap was to reach the city. Utility personnel telephoned all dual-heating customers asking them to switch manually to their alternate fuel. The next day the local radio station asked consumers every 30 minutes to reduce electricity consumption and explained the problem with the load-management system. The utility avoided a peak despite the temporary loss of the system.

Non-Residential Load Controlled

In Watertown, S.D., the 7,700-meter municipal utility's load-management system controls nonresidential loads through changes in voltage control and the water pumping system. The utility drops its voltage from 124 V to 117 V at substations, which is about 112 V at the service point, according to Peter Swanson of Watertown. When the utility is about 800 kW away from its peak, utility operators begin dropping voltage. At 400 kW from the peak the utility lowers voltage to 117 V.

The town also shuts off the electric pump for the water supply system when the utility nears its peak. For emergencies, such as fire protection, the water system has two gas-fired engines that pump water if necessary. The utility alerts water plant operators when electric demand is within one MW of peak.

The utility, whose winter peak of 3,009 MW and summer peak of 3,300 MW are almost equal, can save $26,000 for each megawatt shaved from the peak, Swanson said.

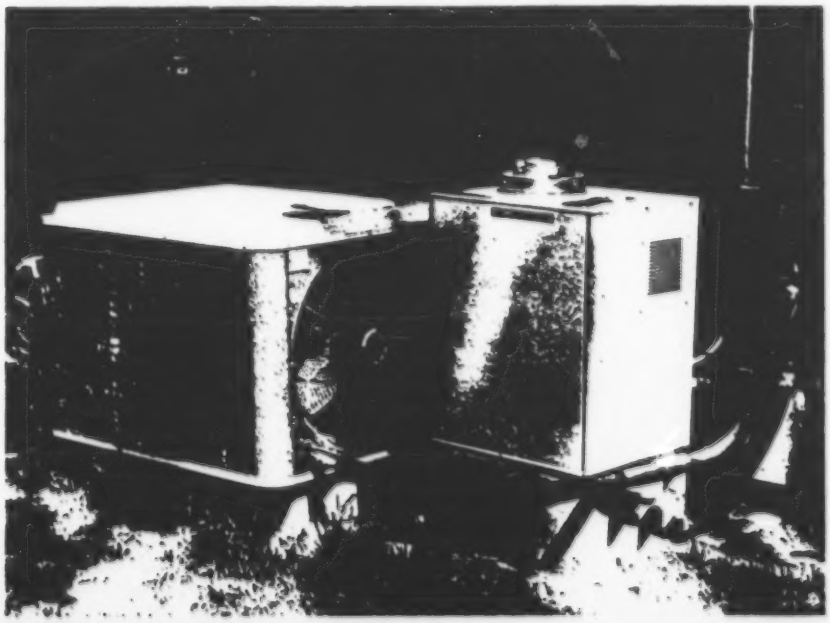
Orange City Leases System

The load-management system in Orange City, Iowa, is being financed under an uncommon lease-purchase agreement which provides the city with the option to buy the system at any time. The 2,110-meter utility is controlling more than 400 central air conditioners and 300 water heaters with the system, which is tied to the privately owned cable communications operation serving the city. The utility also controls voltage at three substations.

Under the agreement, designed like a traditional financing-lease agreement, the cost of the system and interest are amortized over time, said Allen Roos, manager of the Orange City utility. The city makes equal monthly payments. The agreement allows the city to sign a new yearly contract each fiscal year, which prevents the agreement from being considered part of the city's debt, Roos said. Failure of the City Council to appropriate money for the payments would terminate the agreement.

'The (Ortonville) system has paid for itself in two-and-one-half years of operation and the utility has been able to purchase a backup computer for it.'

Ortonville, Minn., consumers get an incentive rate to use a dual-fuel heating system. This is a combination electric furnace (not shown) and natural gas system, right, with a heat pump-air conditioner, left, used during moderate temperatures. Photo courtesy Ortonville Water and Light Department

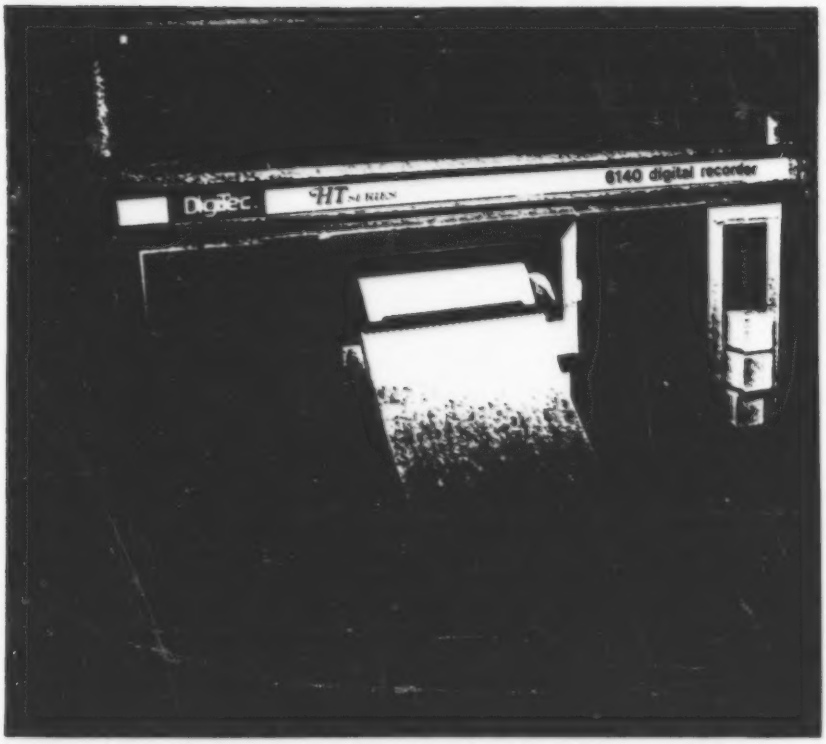


When the system was installed in 1981 the system peak was 8,730 kW, with a load factor in the mid-50 percent range, he said. In 1983 the peak was up to 10,000 kW, but the system load factor was about 63 percent.

Reliability Important

Valley City, N.D., a city of 7,000 with a 4,000-meter municipal electric utility, installed a direct-control load-management system more than three years ago. Because the utility is billed for its wholesale power on a 30-minute demand basis, reliability of the system is important if the system is to save Valley City money, according to Leif Ravnaas, utility superintendent. With 387 receivers installed in 1983 the utility was able to control 5,368 kW of its load.

Ravnaas offered a general comparison of two types of load-management systems on cost and security. In one system the signal is transmitted by radio and in the other by power line. While a radio-type system generally costs less per control point than a power line system in a high-density area, the power line carrier may be cheaper in a low-density



A printout provides Orange City with a continual recording of loads being managed with the system acquired under a lease-purchase agreement. Photo courtesy Orange City

area, he said.

A second factor to consider in choosing a system is its security. A radio control signal—unlike a powerline signal—can be easily blocked by any metal object shielding the receiver. In either type, "you have to decide what will happen if all the points on the system fail," Ravnaas said.

To improve reliability of any system utilities should have backup hardware; keep well-trained personnel, with authority to take steps when an emergency occurs, on the job continually; and routinely check control equipment when it arrives and after installation, Ravnaas said. Of 500 control switches installed in Valley City, 23, or 5.2 percent, have failed, he said.

Problems Not a Barrier

Keith Bartels, an engineer with the engineering consulting firm Martin and Associates of Mitchell, S.D., discussed some of the challenges load management can put before Missouri Basin systems and strategies for meeting those challenges. "There are a great number of folks who strongly believe in load management," Bartels said. "Yet you are all sitting here as members of a group. You can look at this from an individual perspective—what it will do for your community—but you are all members of Missouri Basin too. You need to think about what the overall effect will be on Missouri Basin.

"Generation capacity has to be paid for," Bartels said. "Who is going to pay for it?" If Missouri Basin members all cut back the supplemental power they purchase, the agency could lose revenue, he said. "Where does that revenue shortfall get made up?"

The first few member systems that used load management to reduce supplemental power needs saved money, Bartels said. "Basically that savings came from all the rest of the members." The second group of two or three utilities that installed load-management systems saved money, but not as much as the first group. "It's like a little pie—the community that does it last doesn't save," he said.

"One of the absolute requirements of load management is to remember you are in this business to sell electricity," said Bartels. "When we begin unselling our basic product we've got a real problem. What load management can do is enable you to market that energy at a cost level where people can buy it. That can be a tremendous thing."

The joint-action agency should look at alternatives to raising the price of electricity to make up for reduced revenue. "One of the alternatives is creative marketing," said Bartels. He suggested selling excess capacity at a discount rate to member systems, which will allow member utilities to pass the savings to consumers.

"As a group there are savings to be had, but as a fragmented entity that would be difficult," he said. "I think the coordinated response is the way to go."

Load Management Nationwide

SIOUX FALLS, S.D.

CLARK W. GELLINGS, program manager of the Electric Power Research Institute's demand and conservation program, described at the Sioux Falls seminar the routes being taken toward load management by utilities across the country:

- **Peak Clipping**—Defined as reduction of electricity use during peak hours, peak clipping can be accomplished through programs that include energy conservation, interruptible loads, heat pumps and dual-fuel space heating systems.
- **Valley Filling**—The purpose of valley filling is to increase off-peak loads, particularly those that would have been fossil-fueled. Ways to fill load valleys include introduction of new electrical mechanisms, such as electric vehicles and new industrial loads, and using thermal energy storage to capture energy generated on peak for use off peak.
- **Load Shifting**—Utility programs that move load from peak to off-peak periods, known as load shifting, often include water heater control, air conditioner control, storage heating or cooling, or interlocks, which are electromechanical devices that prevent coincident use of major appliances.
- **Conservation**—Strategic conservation, defined as reduction of electrical use during peak hours, can be useful, although current industry trends are away from conservation and toward load-shaping weatherization programs and space and water heat pumps.

Gellings listed 11 benefits of load management: (1) reducing the need for critical fuels; (2) reducing or postponing capital investment in new construction; (3) keeping electricity costs stable; (4) increasing electricity sales; (5) providing customers with options on how much they spend monthly on electricity; (6) lowering utility risks by investing in alternatives; (7) increasing operating flexibility and system reliability; (8) reducing unit costs through more efficient loading of existing and planned generating facilities; (9) satisfying regulatory constraints; (10) minimizing potential impact on the environment; and (11) improving the image of the utility. LORI A. WOEHRLE

REMARKS BY

ERNIE JACKSON
CHIEF ENGINEER
CORNWALL ELECTRIC
CORNWALL, ONTARIO

"DISTRIBUTION PROCESSING SCADA SYSTEM"

AT

INNOVATIONS IN DISTRIBUTION LOAD MANAGEMENT SEMINAR

SKYLINE AIRPORT HOTEL
TORONTO, ONTARIO

WEDNESDAY, NOVEMBER 29, 1989

HISTORY

CORNWALL ELECTRIC BECAUSE IT PURCHASES IT'S ENERGY REQUIREMENTS ON THE INTERNATIONAL MARKET HAS HAD A SPECIAL MOTIVATION TO INVESTIGATE DEMAND MANAGEMENT. NOT BEING CONNECTED TO THE ONTARIO HYDRO GRID WE FOUND THE EFFECTIVE DEMAND CHARGE THAT WE WERE PAYING IN SOME CIRCUMSTANCES WAS TEN TIMES THAT WHAT OTHER ONTARIO MUNICIPAL UTILITIES WERE PAYING.

UNFORTUNATELY THE INSTRUMENTATION OF THE 1970'S PROVIDED US WITH VERY LITTLE DATA TO WORK WITH TO TRY TO MINIMIZE THESE COSTS. FURTHER MORE AT THAT TIME THE COST OF SCADA SYSTEMS (SUPERVISORY AND DATA ACQUISITION) WAS PROHIBITIVE.

IN THE EARLY 80'S THE COST OF SUCH SYSTEMS STARTED TO COME DOWN AS THE TECHNOLOGY MATURED

CORNWALL ELECTRIC TEL NO. 1 613 932 6498 NOV 20,89 16:21 P.02

IT SOON BECAME APPARENT TO US THAT WE NEEDED TO TAKE A BROAD LOOK AT THE SITUATION AND DETERMINE WHAT OTHER SYSTEMS WE MIGHT EVENTUALLY WANT TO INTERFACE WITH THE SCADA SYSTEM.

FROM THIS EXERCISE WE QUICKLY DETERMINED THAT ANYTHING WE PURCHASED SHOULD BE 1) MULTIPLE SOURCED
2) AND CONFORM TO INDUSTRY STANDARDS.

WE DID NOT WISH TO REINVENT THE WHEEL.

CORNWALL ELECTRIC TEL No. 1 613 932 6496 Nov 20,89 16:21 P.03

STRUCTURAL REQUIREMENT LIST

1. ALL HARDWARE AND SOFTWARE MUST BE INDUSTRY STANDARD, MULTIPLE SOURCED AND OFF THE SHELF

   "OFF THE SHELF" MEANING THAT THE COMPONENTS HAVE BEEN INSTALLED IN OTHER APPLICATIONS AND HAVE HAD AT LEAST THREE UPWARD COMPATIBLE REVISIONS

CORNWALL ELECTRIC TEL NO. 1 613 932 6498 NOV 20,89 16:22 P.04

2. ALL DATA FILES USED BY THE COMPUTER SYSTEM SHOULD CONFORM TO INDUSTRY STANDARD DATA FORMATS AND FILE STRUCTURES

"INDUSTRY STANDARD FILE FORMAT" MEANS A PUBLISHED AND SUPPORTED STRUCTURE FOR WHICH SEVERAL SOFTWARE COMPANIES DEVELOP AND SELL FILE MANAGEMENT PACKAGES eg. LOTUS WK1 FILE FORMATS AND dBASE III FILE FORMATS.

CORNWALL ELECTRIC TEL No. 1 613 932 6498 Nov 20.89 16:22 P.05

3. ALL PROCESSORS CENTRAL AND REMOTE MUST BE PROGRAMMED IN THE SAME HIGH LEVEL LANGUAGE AND MAKE USE OF THE SAME OPERATING SYSTEM. PROVEN PREFABRICATED SOFTWARE PACKAGES ARE TO BE USED WHERE EVER POSSIBLE.

CORNWALL ELECTRIC TEL No. 1 613 932 6498 Nov 20,89 16:23 P.06

THE SYSTEM WHICH WAS EVENTUALLY CHOSEN CONSISTED OF A STANDARD IBM AT COMPUTER AS THE MASTER STATION WHICH TALKED TO STANDARD IBM CLONES AT EACH OF THE 6 SUBSTATIONS. WITH THESE UNITS IF A BOARD FAILS OR SOMETHING ELSE GOES WRONG YOU JUST GO TO COMPUTERLAND OR SOME OTHER COMPUTER RETAILER PURCHASE THE DAMAGED COMPONENTS AND YOUR BACK ON LINE. IN 4 YEARS OF OPERATION WE HAVE NEVER BEEN OFF LINE BECAUSE OF AN RTU (REMOTE TERMINAL UNIT) OR MASTER STATION FAILURE FOR MORE THAN 15 MINUTES.

THE OPERATING SYSTEM WHICH WAS CHOSEN WAS A PRODUCT CALLED CONCURRENT DOS WHICH PERMITS THE OPERATION OF VIRTUALLY ANY SOFTWARE THAT WILL OPERATE UNDER DOS.

CORNWALL ELECTRIC TEL No. 1 613 932 6498 Nov 20,89 16:23 P.07

ENGINEERING INFORMATION STRUCTURE

(SEE DIAGRAM)

ULTIMATELY IT IS INTENDED TO LINK

1) THE ACCOUNTING DATA SYSTEM WHICH INCLUDES THE METERING DATA.

2) THE HISTORIC ENGINEERING DATA SUCH SYSTEM TOPOLOGY.

3) THE SCADA SYSTEM.

4) LOAD MANAGEMENT SYSTEM

THIS WILL ALLOW US TO;

1) CONFIGURE THE SYSTEM TO MINIMIZE LOSSES THROUGH AN ENGINEERING PACKAGE BASED ON CURRENT LOADS AND SYSTEM TOPOLOGY.

2) PREDICT WHEN PEAKS WILL OCCUR WITH MORE ACCURACY AND IDENTIFY WEAK SPOTS IN THE DISTRIBUTION SYSTEM. THIS WILL ENABLE MORE APPROPRIATE USE OF LOAD CONTROL DEVICES.

3) PREDICT DURATION OF PEAKS AND DETERMINE THE MOST EFFECTIVE WAY OF MINIMIZING THEM.

CORNWALL ELECTRIC TEL No. 1 613 932 6498 Nov 20,89 16:23 P.08

ENGINEERING INFORMATION
SYSTEM STRUCTURE

G L
STORES INVENTORY
BILLING
WORK ORDER SYSTEM

SYSTEM CONFIGURATION
DIAGRAM
DETERMINATION OF OPTIMUM
SYSTEM TOPOLOGY
DUD CAL

REAL TIME DATA GATHERING
REAL TIME DATA PROCESSING

CORNWALL ELECTRIC TEL No. 1 613 932 6498 Nov 20,89 16:24 P.09

SOFTWARE LINKS IN SCADA SYSTEM
(SEE DIAGRAM)

THE MASTER COMPUTER AT THE WORK CENTER RUNS THE SOFTWARE ON THIS SIDE OF THE LINE. THE RTU RUNS ALL THE PROGRAMS ON THE OTHER SIDE.
THE ADVANTAGE OF CONCURRENT DOS IS THAT ALL THESE PROGRAMS RUN SIMULTANEOUSLY.
THIS MEANS THAT YOU CAN BE DOING ANALYSIS FOR EXAMPLE IN ONCALC OR LOTUS 123 WHILE THE SCADA SYSTEM IS RUNNING. ALL OF THIS CAN BE DONE IN REAL TIME IF REQUIRED.
IT ALSO MEANS THAT IF YOU WANT TO RUN OTHER PROGRAMS AT THE RTU LEVEL FOR EXAMPLE TO RECORD THE COLD LOAD PICK UP YOU CAN.

CORNWALL ELECTRIC TEL No. 1 613 932 6498 Nov 20,89 16:24 P.10

HARDWARE CONTACTS
RELAYS
DIN
DOM
SRRTU
ACMIN
ACM 3800 WITH RS232 CONNECTOR
SR
RLTCON
IOTEMP
DISPATCHER
OMSPEC
BRAIN
OMCALC
OMVIEW
SUPERINENDENT
EXSISTING
PLANED

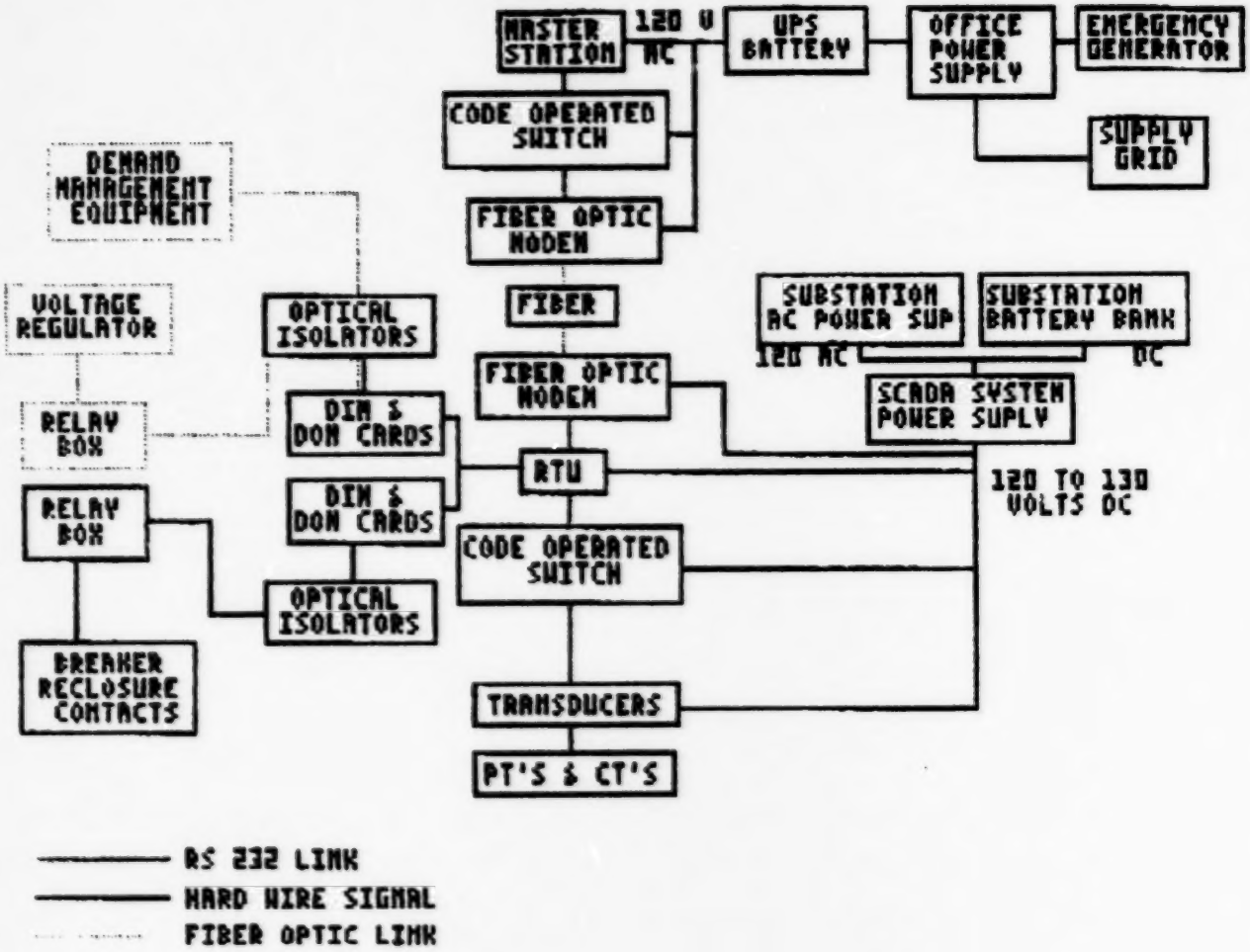
HARDWARE CONFIGURATION
(SEE DIAGRAM)

AT THE TOP IS THE MASTER STATION WHICH IS SUPPLIED BY A UPS WHICH IS IN TURN SUPPLIED BY THE OFFICE POWER SUPPLY WHICH IS BACKED UP BY AN EMERGENCY GENERATOR.

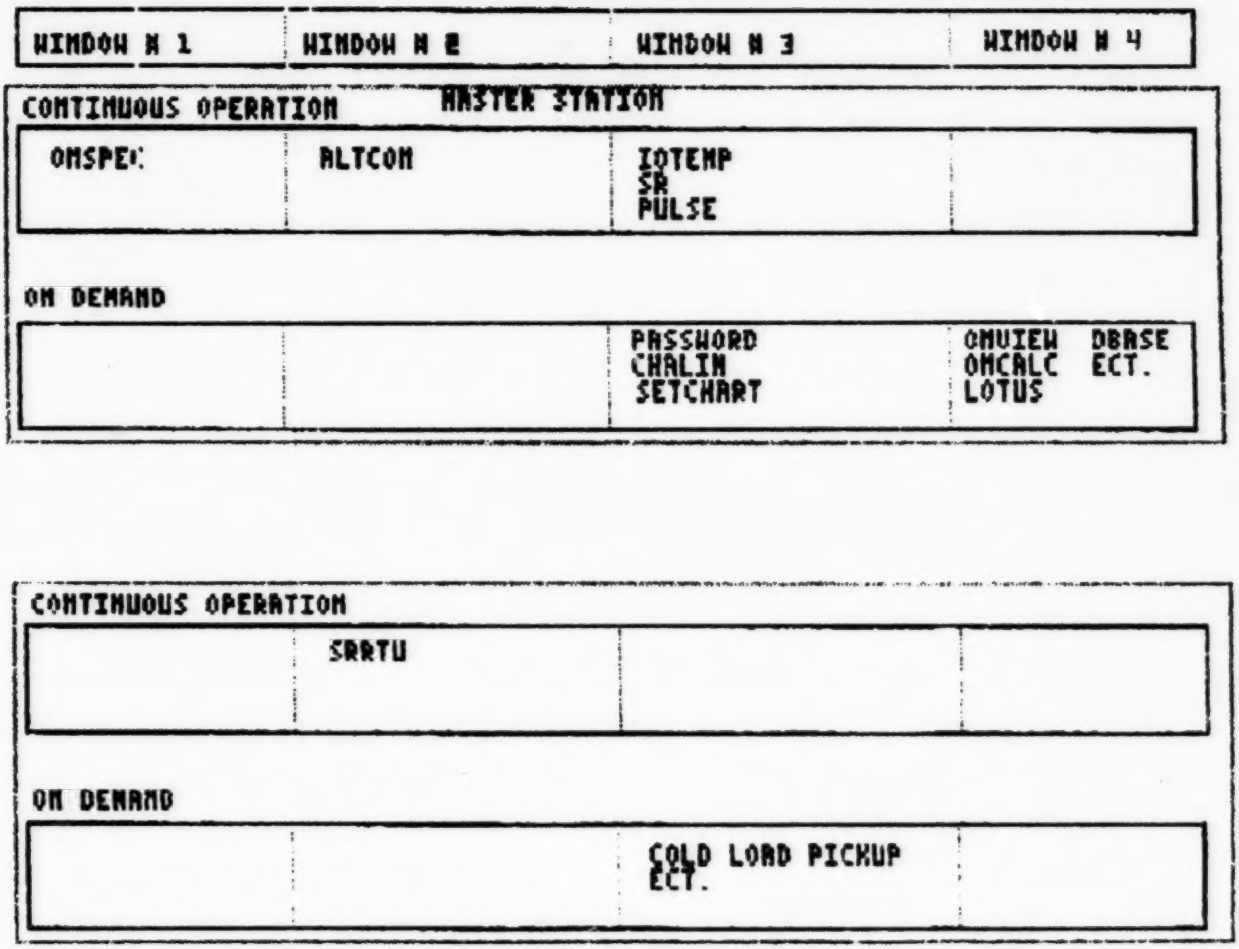
NEXT DOWN THE LINE IS THE CODE OPERATED SWITCH WHICH MULTIPLEXES THE SIGNALS FROM THE SUBSTATIONS. THE SIGNAL IS THEN SENT TO THE FIBER OPTIC MODEM WHICH SENDS THE SIGNALS THROUGH THE FIBER TO THE MODEMS CONNECTED TO THE RTU'S. WHICH ARE IN TURN CONNECTED TO THE TRANSDUCERS AND THE INPUT OUTPUT CARDS WHICH CONTROL POINT OPERATION.

CORNWALL ELECTRIC TEL No. 1 613 932 6498 Nov 20,89 16:25 P.12

HARDWARE CONFIGURATION



SOFTWARE STRUCTURE
WITH
CONCURRENT DOS OPERATING
SYSTEM



TRANSDUCERS

CORNWALL STARTED WITH A GREEN FIELD - NOTHING IN PLACE.

A PRODUCT DEVELOPED BY POWER MEASUREMENTS OF VICTORIA, B.C. WAS SELECTED BECAUSE IT WAS OFF THE SHELF AND IT HAD AN OPERATING HISTORY AS WELL AS AN RS232 PORT

CORNWALL ELECTRIC TEL No. 1 613 932 6498 Nov 20,89 16:26 P.15

ACM 3600

MEASURES ALL OUR 3 PHASE ANALOGUE POINTS -VOLTS, AMPS, WATTS.VAR, PF, MWHRS IN ONE PACKAGE $2,000 TO $3,000

THE UNITS HAVE AN ACCURACY IN THE ORDER OF 1% WHICH WAS WELL WITHIN THE LIMITS ACCEPTABLE FOR OUR APPLICATION (NOT CONSUMER AND CORPORATE AFFAIRS APPROVED)

INITIALLY WE WERE NOT PARTICULARLY HAPPY WITH THIS PRODUCT BECAUSE OF THE FALSE ALARMS THAT THE UNIT PRODUCED. AFTER A 6 MONTH STRUGGLE JOMITEK OUR CONSULTANT WAS ABLE TO IDENTIFY THE SOURCE OF THE ERRORS AND HAD THE EPROMS RECODED BY POWER MEASUREMENTS AND THE ERRORS STOPPED.

CORNWALL ELECTRIC TEL No. 1 613 932 6498 Nov 20,89 16:26 P.16

MORE WORRISOME TO US WAS THE PROPENSITY OF THE COMMUNICATIONS CHIPS IN THE UNITS TO SELF DESTRUCT WHEN SYSTEM ABNORMALITIES OCCURRED. WE WERE ABLE TO SOLVE THIS PROBLEM IN TWO WAYS

1) THE INSTALLATION OF OPTICAL ISOLATION

2) AND THE COMMUNICATIONS CHIPS WERE PLACED IN SOCKETS SO THAT THEY COULD BE REPLACED EASILY AND QUICKLY IF THEY DID SELF-DESTRUCT. (THE CHIPS THEMSELVES ARE QUITE INEXPENSIVE $2 TO $3)

CORNWALL ELECTRIC TEL NO. 1 613 932 6498 NOV 20,89 16:27 P.17

CODE OPERATED SWITCH

ORIGINALLY THE CONCEPT WAS TO TAKE THE RS232 SIGNALS FROM 4 OR 5 ACM'S AND COMBINE THEM INTO ONE SIGNAL USING SOFTWARE IN THE RTU.

THIS PROVED TO BE MORE TIME CONSUMING THAN OUR SCHEDULE ALLOWED SO WE SELECTED A HARDWARE SOLUTION WHICH COMBINED THE SIGNALS AND CODED THEM SO THAT THE RTU COULD RECOGNIZE WHICH ACM 3600 ORIGINATED THE SIGNAL.

AGAIN THIS PRODUCT WAS OFF THE SHELF AND SEVERAL ALTERNATIVE SUPPLIERS WERE IDENTIFIED

CORNWALL ELECTRIC TEL No. 1 613 932 6498 Nov 20,89 16:27 P.18

RTU

AN INDUSTRIAL IBM XT CLONE WAS SELECTED AS THE RTU FOR THE FOLLOWING REASONS

1. IT GAVE US MAXIMUM FLEXIBILITY IN SELECTION OF SOFTWARE
2. THE PRODUCT HAD A PROVEN TRACK RECORD IN OTHER INDUSTRIAL APPLICATIONS
3. SERVICING AND PARTS ARE EASILY AVAILABLE LOCALLY
4. SELF DIAGNOSTIC PROGRAMS ARE READILY AVAILABLE
5. THE TECHNOLOGY WAS FAMILIAR TO OUR OWN STAFF
6. A WIDE VARIETY OF ADD-ON CARDS ARE AVAILABLE FOR THE MACHINE AND DO NOT REQUIRE ANY DEVELOPMENT
7. THE SELECTION OF THIS MACHINE WOULD PROVIDE AN UPWARD PATH SHOULD AT A LATER DATE MORE POWER BE REQUIRED (AT,386,?)

CORNWALL ELECTRIC TEL No. 1 613 932 6498 Nov 20.'89 16:27 P.19

DIM. AND DOM CARDS

THE SELECTION OF AN IBM PC CLONE MEANT THAT DIGITAL INPUT AND OUTPUT CARDS HAD TO BE ADDED SO THAT THE SOFTWARE COULD COMMUNICATE WITH THE EXTERNAL HARDWARE. THESE PRODUCTS WERE EASILY OBTAINABLE OFF THE SHELF FROM REGULAR CARD SUPPLIERS.

THE MAXIMUM CONFIGURATION OF AN RTU BECAUSE OF THE LIMITED NUMBER OF EXPANSION SLOTS IN AN XT AND SOFTWARE LIMITATIONS IS

-330 ANALOGUE POINTS

-96 DIGITAL INPUT POINTS

-96 DIGITAL OUTPUT POINTS

IN THE EVENT THAT MORE POINTS THAN THIS ARE REQUIRED IT IS NECESSARY TO GO TO A SECOND RTU

CORNWALL ELECTRIC TEL No. 1 613 932 6498 Nov 20.89 16:28 P.20

WE FOUND THIS TO BE NECESSARY AT ONE OF OUR STATIONS SO WE SIMPLY CASCADED THE RTU'S

CORNWALL ELECTRIC TEL No. 1 613 932 6498 Nov 20.89 16:28 P.21

COMMUNICATIONS

-WE EXAMINED THE USE OF BELL TELEPHONE LINES (DEDICATED LINES)

-RADIO LINKS

-FIBEROPTIC LINKS

-MICROWAVE

-POWERLINE CARRIER

CORNWALL ELECTRIC TEL No. 1 613 932 6498 Nov 20,89 16:29 P.22

BELL LINES -9600 BAUD HIGH ERROR RATE

-NO CONTROL OVER THE USE OF LINES (NOT SECURE)

-HIGH LIFE CYCLE COST

-NO ROOM FOR EXPANSION

RADIO LINKS -DIFFICULT TO GET

-DEDICATED FREQUENCY

-INTERFERENCE FROM OTHER SOURCES (NOT SECURE)

-MICROWAVE -TO EXPENSIVE

CORNWALL ELECTRIC TEL No. 1 613 932 6498 Nov 20,89 16:29 P.23

-FIBER OPTIC -COST EFFECTIVE
RELATIVE TO BELL (7 YEAR
LIFE CYCLE BREAK EVEN
POINT)
-LOTS OF ROOM FOR EXPANSION
-VERY SECURE (CAN BE BROKEN
BUT NOT INTERFACED)
-MODEMS LIKELY TO BE OBSOLETE
BUT NOT FIBER
-EASILY REPAIRED
-ALL IN HOUSE SKILLS
-MODEMS INEXPENSIVE AND
MULTIPLE SOURCED

CORNWALL ELECTRIC TEL No. 1 613 932 6498 Nov 20,89 16:29 P.24

MASTER STATION

THE SELECTION OF THE MASTER STATION WAS DICTATED BY THE FOLLOWING CRITERIA

- -AVAILABLE SOFTWARE
- -REPARABILITY
  - -HOW EASILY ARE PARTS AVAILABLE
  - -HOW EASY IS IT TO IDENTIFY HARDWARE PROBLEM
  - -HOW EASY IS IT TO FIND SERVICE PEOPLE
- -EXPANDABILITY
  - -CAN MEMORY BE ADDED ?
  - -CAN ADDITIONAL HARDWARE FUNCTIONS BE ADDED
- -UPGRADEABLITY
  - -IS IT POSSIBLE TO TRANSPORT SOFTWARE UPWARDS TO A BIGGER MACHINE
  - -IS THERE AN ONGOING PROGRAM FOR PRODUCT IMPROVEMENT
- -COST

CORNWALL ELECTRIC TEL No. 1 613 932 6498 Nov 20,89 16:29 P.25

RELAY BOX

THIS WAS THE AREA WHICH WE EXPECTED THE LEAST PROBLEM AND EXPERIENCED THE MOST.

WE SELECTED AN OFF THE SHELF SCADA RELAY BOX BECAUSE IT WAS WIDELY USED ON OTHER SYSTEMS.

WE HAD EXTENSIVE PROBLEMS WITH THIS PRODUCT BECAUSE OF QUALITY CONTROL
-THE WRONG RELAYS WERE INSTALLED IN CLOSE TO 20 % OF THE BOXES
-SEVERAL HAD SOLDERING ERRORS

THE DEVICES WERE INSTALLED BEFORE THESE PROBLEMS WERE RECOGNIZED

CORNWALL ELECTRIC TEL No. 1 613 932 6498 Nov 20,89 15:30 P.26

RESULTS

-THE RESULTS HAVE BEEN VERY ENCOURAGING FOR US

1) IN THE MONTH OF JANUARY ALONE LAST YEAR CORNWALL ELECTRIC WAS ABLE TO REDUCE ITS DEMAND CHARGE BY OVER $50,000. THIS WAS DONE BY REDUCING VOLTAGE TO THE BOTTOM END OF THE CSA STANDARD FOR 3 HOURS DURING THE PEAK DEMAND. WE WERE ABLE TO PREDICT WHEN THE PEAK WAS TO OCCUR WITHIN 15 MINUTES WITH THIS EQUIPMENT. WHEN YOU COMPARE THIS ONE SAVING TO A TOTAL COST FOR THE SYSTEM $350,000 TO CORNWALL ELECTRIC YOU SOON SEE THAT IT HAS BEEN A GOOD INVESTMENT.

2)QUITE ASIDE FROM THE ENERGY MANAGEMENT ASPECTS OF THE SCADA SYSTEM THE SAFE OPERATION OF THE DISTRIBUTION SYSTEM HAS BEEN MARKEDLY INCREASED. FIELD PERSONNEL ARE USEING MORE NON-RECLOSURE ASSURANCES (HOLD-OFFS) AND WE

CORNWALL ELECTRIC TEL No. 1 613 932 6498 Nov 20.89 16:30 P.27

CAN ISOLATE AREAS MUCH QUICKER NOW.

3) A BETTER UNDERSTANDING OF OUR LOAD ALLOWS THE STAFF TO PLAN FUTURE EXPANSION WITH A BETTER HANDLE ON THE ECONOMICS AND CAPACITY OF THE SYSTEM.

4) BECAUSE OF THE UNIQUE WAY IN WHICH CORNWALL PURCHASES POWER (ON THE INTERNATIONAL MARKET) THE ADDITIONAL INFORMATION THAT THE SCADA SYSTEM PROVIDES ALLOWS US TO NEGOTIATE MUCH MORE COST EFFECTIVE CONTRACTS WITH OUR SUPPLIERS.

CORNWALL ELECTRIC TEL No. 1 613 932 6498 Nov 20,89 16:31 P.28

THE FUTURE

- -LOAD MANAGEMENT .HOT WATER TANKS
- -AUTOMATED VOLTAGE CONTROL
- -PARALLEL AND PEAKING GENERATION CONTROL
- -INTERFACE WITH BILLING AND CAD SYSTEM
- -INTEGRATION OF ENGINEERING CALCULATION PROGRAM FOR BETTER SYSTEM DESIGN
- -COMPUTER UPGRADE TO ACCOMMODATE TRANSMISSION SPEEDS FASTER THAN 9600 BAUD
- -VIDEO CAMERA SUBSTATION AND SWITCH SURVEILLANCE

CORNWALL ELECTRIC TEL No. 1 613 932 6498 Nov 20,89 16:31 P.29

REMARKS BY

CLIFF ENGSTROM
GENERAL MANAGER
MASSENA ELECTRIC
MASSENA, NEW YORK

"ECONOMIC IMPACT OF LOAD MANAGEMENT"

AT

INNOVATIONS IN DISTRIBUTION LOAD MANAGEMENT SEMINAR

SKYLINE AIRPORT HOTEL
TORONTO, ONTARIO

WEDNESDAY, NOVEMBER 29, 1989

MASSENA ELECTRIC DEPARTMENT

GENERAL SYSTEM DATA

YEAR STARTED		1981
SERVICE AREA		130 SQ. MILES
CUSTOMERS		8500
PEAK DEMAND	JAN. 1989	24,996 KW
KWHR SOLD	(1988)	101,510,014
GROSS REVENUE	1988	$5,585,248
SALES MIX -	RESIDENTIAL 60%	
	COMMERCIAL 11%	
	INDUSTRIAL 28%	

APPROXIMATELY 10% OF RESIDENTIAL CUSTOMERS HAVE ELECTRIC HEAT.

HOW LOAD MANAGEMENT MAY FURTHER UTILITY OBJECTIVES

- Reduce Cost to Customers
  - Maintain Service Quality
  - Significant Savings
  - Perceived Benefit
- Reduce Cost to Utility
  - Lower Current Costs
  - Deferred Capital Investment

MASSENA ELECTRIC DEPARTMENT

WATER HEATER INCENTIVE PROGRAM

POWER COSTS

KW	SOURCE	DEMAND COST	ENERGY COST
22,400KW	HYDRO	$1.00/KW-MO	$.00262/KWHR
BALANCE*	NUCLEAR	$11.67/KW-MO	$.015/KWHR

* 80% RATCHET BASED ON HIGHEST 30 MIN. YEARLY DEMAND. RATCHET NOT FIXED HAS VARIED FROM 93% TO 75%.

ENERGY DISPATCHED ON RATION OF HYDRO ALLOCATION TO PEAK DEMAND.

Chart 9

MASSENA HOURLY LOAD CURVES

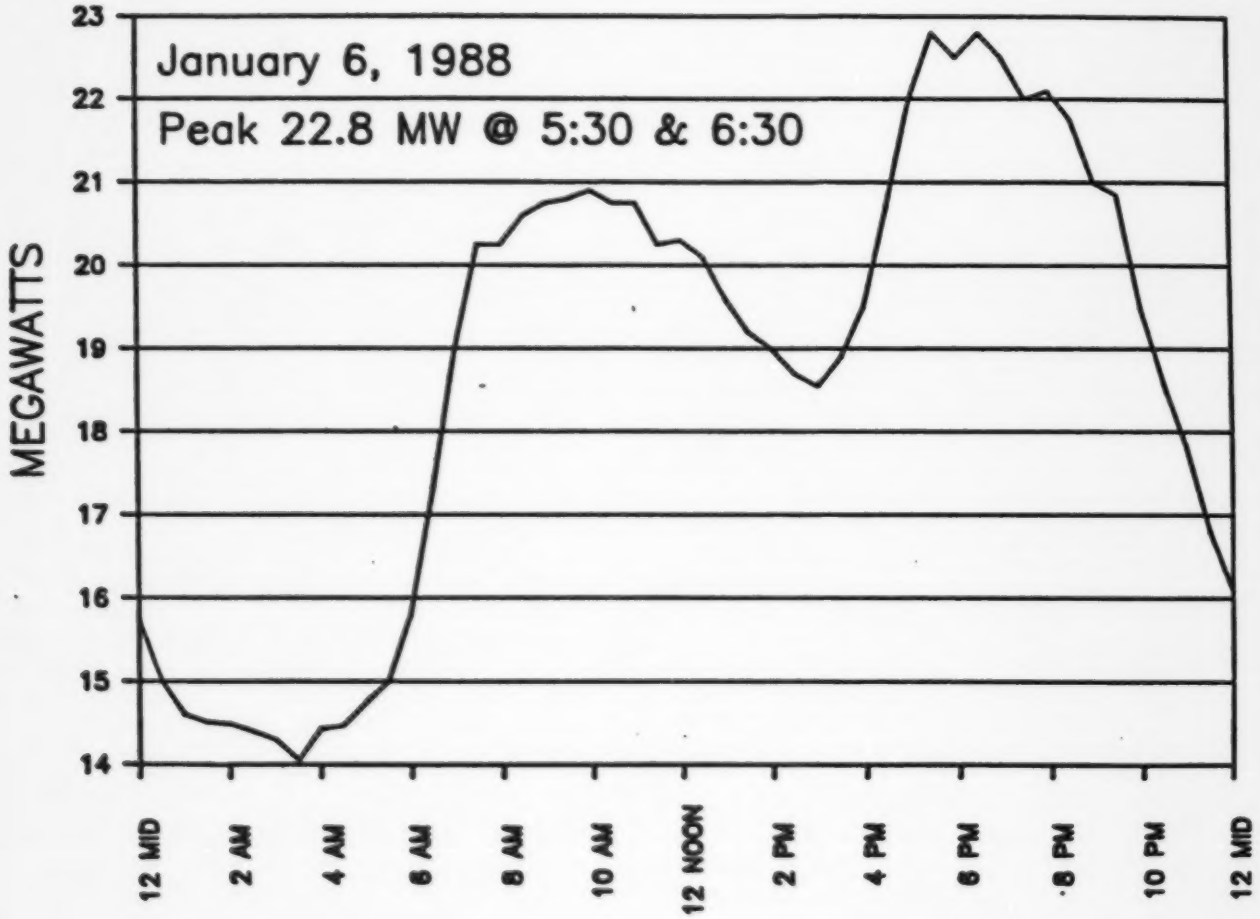
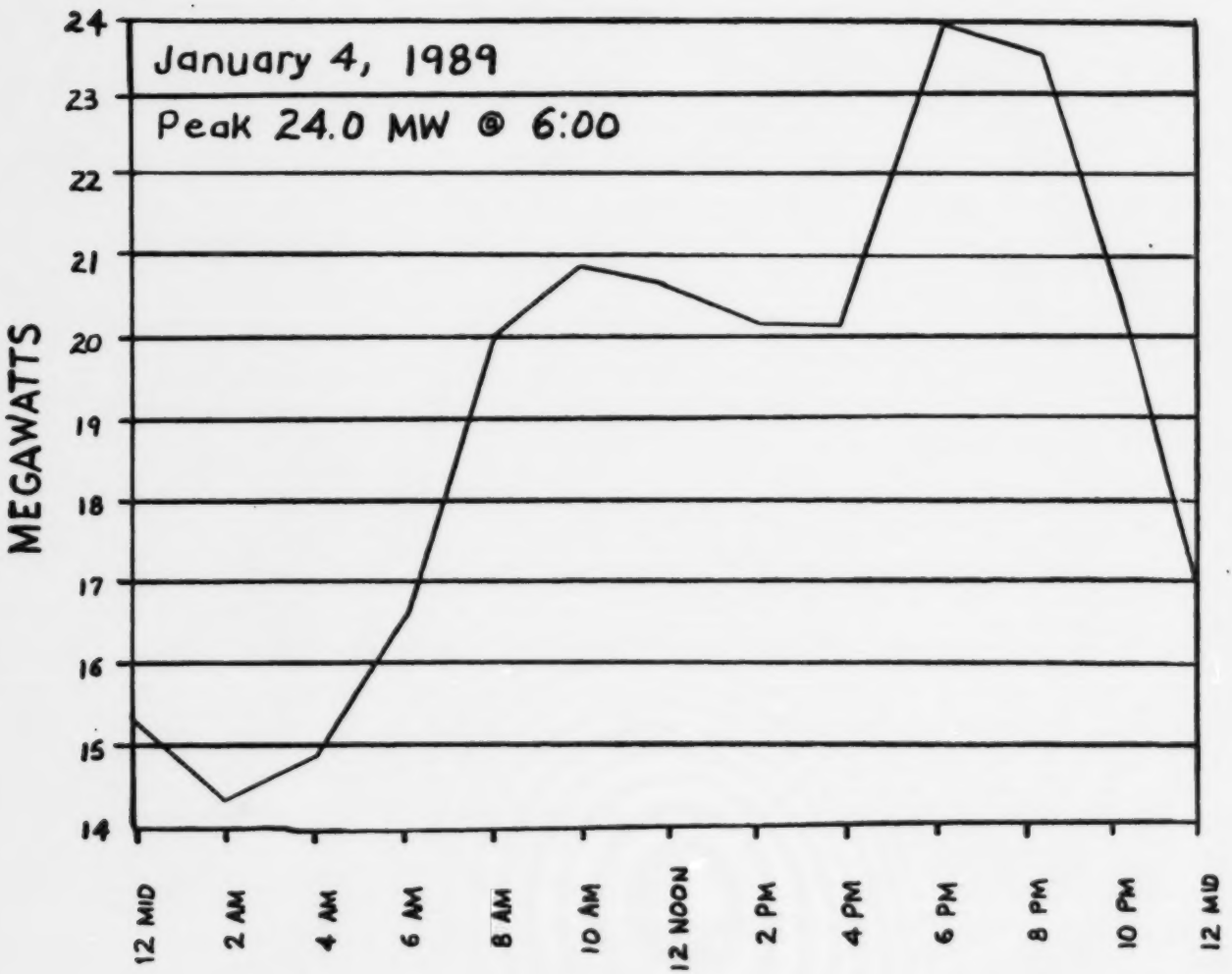


Chart 9

MASSENA HOURLY LOAD CURVES



MASSENA ELECTRIC DEPARTMENT

WATER HEATER INCENTIVE PROGRAM

CUSTOMER SAVINGS

$25.00 INSTALLATION CREDIT ON ELECTRIC BILL

$2.00 PER MONTH CREDIT ON ELECTRIC BILL

FREE:

1. WATER HEATER INSULATION JACKET
2. LOW FLOW SHOWER HEADS
3. LOW FLOW FAUCET AERATORS

MINIMUM TANK SIZE - 50 GAL.

(EXPECT TO EXPAND TO 40 GAL. IN 1990).

MASSENA ELECTRIC DEPARTMENT

WATER HEATER INCENTIVE PROGRAM

INSTALLATION COSTS

SWITCH AND SOCKET		$104.50
WIRING		35.00
INSPECTION		15.00
MISC. INSTALLATION & RECORD KEEPING		25.00
INSULATION JACKET		10.50
SHOWER HEAD	2 @ $ .45	.90
FAUCET AERATOR	2 @ $3.19	6.38
	TOTAL	$197.28
	INCENTIVE CREDIT.	$ 25.00
TOTAL INITIAL COST		$222.28

MASSENA ELECTRIC DEPARTMENT

WATER HEATER INCENTIVE PROGRAM

ECONOMICS AND PAYBACK

PROJECTED DEMAND REDUCTION - 1KW PER WATER HEATER

PROJECTED LIFE OF SWITCHES - 10 YEARS

ANNUAL POWER COST SAVINGS PER SWITCH - $125.00 TO $150.00

ESTIMATED PAY-BACK 3 YR INCLUDING AMMORTIZATION OF FRONT-END EQUIPMENT AND SOFTWARE.

MASSENA ELECTRIC DEPARTMENT

INDUSTRIAL INTERRUPTABLE RATE

DEMAND CREDIT $4.50/MO OF CONTROLLED LOAD ($54/KW. YR)

MINIMUM CONTROLLED LOAD 25KW INITIALLY

POSSIBLE LOADS TO BE CONTROLLED 1989 - 1990:

1. MASSENA ARENA - COMPRESSORS 100+KW
2. WATER PUMPING STATION 50 KW
3. GARAGE HEAT AT MED OFFICE 100 KW

INDUSTRIAL DEVELOPMENT PROSPECTS:

1. FROZEN FOOD WAREHOUSE
2. LUMBER DRYING

REMARKS BY

RON ELLIOT
PRESIDENT
ENERGY MANAGEMENT
ENGINEERING
PEMBROKE, ONTARIO

"LOAD MANAGEMENT FOR NORTHERN UTILITIES"

AT

INNOVATIONS IN DISTRIBUTION LOAD MANAGEMENT SEMINAR

SKYLINE AIRPORT HOTEL
TORONTO, ONTARIO

WEDNESDAY, NOVEMBER 29, 1989

M.O.E. SEMINAR ON
INNOVATIONS in ELECTRICAL DISTRIBUTION LOAD MANAGEMENT
SKYLINE HOTEL, TORONTO
NOVEMBER 29, 1989.

LOAD MANAGEMENT FOR

NORTHERN UTILITIES

Table of Contents

1.0	Introduction
2.0	Load Management System Description
3.0	Selection and Evaluation of Customers' Deferrable Loads
4.0	Reduction in Demand
5.0	Control Strategies
6.0	Utility Savings
7.0	Customers' Discounts
8.0	Results

by

Ronald K. Elliott, B.Sc. P.Eng.

Energy Management Engineering

- Pembroke, Ontario -

November 1989.

1.0 Introduction

1.1 This paper describes the utility load management system designed for and installed in the town of Deep River, Ontario. Deep River is located on the south shore of the Ottawa river, mid way between the cities of Ottawa and North Bay. It began in 1945 as the townsite for Atomic Energy of Canada Ltd. at Chalk River and has a population of about 5000 people.

1.2 Utility load management was considered by Deep River Hydro because it has the second highest retail rates in Eastern Ontario. This northern town has a high density of electric space heating which depresses its average annual load factor to about 64% and causes a relatively high wholesale cost per kilowatt hour.

1.3 After a preliminary review of Institutional, Commercial and Residential loads, it was concluded that many could be deferred during utility peak periods, to reduce the billing demand and therefor the wholesale cost of power. It was recognized that customers' discounts would be necessary to encourage participation.

1.4 After review of commercially available, computer based systems, the Scientific Atlanta system, employing a dedicated FM transmitter, was chosen. This decision was based on its versatility, low cost and ten years of proven experience in U.S. utilities. After the system was ordered, customers' loads were selected and evaluated to complete the system detailed design, estimate utility savings and develope customers' discounts.

1.5 System installation and commissioning was started in late August 1988. The centralized controls and FM transmission equipment were installed at the utility building while radio controlled load switches were installed and connected to loads in customers' premises.

1.6 With this introduction, allow me to proceed with a description of the load management system, controlled loads, utility savings and customers' discounts. I will conclude with discussion of results to date.

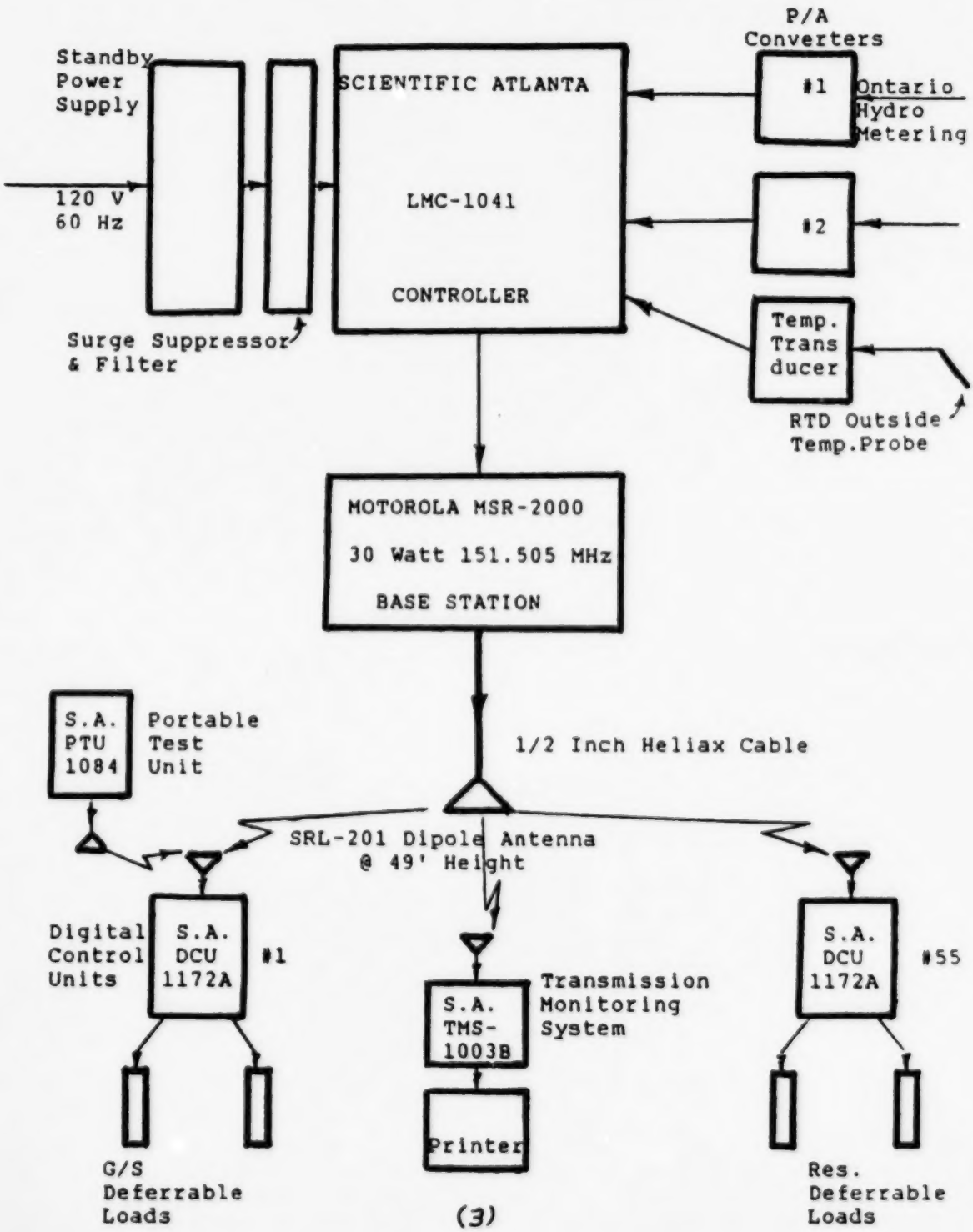
2.0 Load Management System Description

2.1 The block diagram of the Deep River H.E.C. Load Management System shows the major components and sub systems.

- The Scientific Atlanta (SA) Load Management Controller (LMC-1041) is the brain or controlling centre of the utility load management system.

- A Motorola MSR-2000 30 watt, Base Station and Dipole Antenna mounted 49' above ground level, broadcasts the digitally encoded control messages. A carrier frequency of 151.505 MHz is used under licence from the Federal Department of Communications.

DEEP RIVER H.E.C. LOAD MANAGEMENT SYSTEM



- In the field, load switches, or Digital Control Units (DCU),are installed in buildings where the loads are controlled. Each DCU contains a highly sensitive, selective, dual-conversion FM receiver, a filter section which converts the audio information back into digital data, and a microprocessor which decodes the digital data, and operates the control relays based on the information in the digital message. In simpler terms, all the switches hear all the messages, but only the switches coded to respond to the particular message disconnect their loads. The Scientific Atlanta load switches also contain a fail-safe timer which restores the load automatically in case the switch or control systems fail.

- The load switches are supplied by 240 volts 60 Hz power and contain two output relays - one rated for 5 amperes 24 Volts AC and the other for 30 Amperes 240 Volts AC . Typical controlled loads include dual fuel and electrical space and water heaters, air supply fans and heaters, water purification , pumping and ice making equipment.

- The Scientific Atlanta hand held Portable Test Unit (PTU-1084) is used by utility staff to check that load switches will respond to the transmitted address and function properly.

- The transmitted messages are also received by the Scientific Atlanta Transmission Monitoring System and a record of all transmissions is provided. This confirms that the intended control signals are in fact transmitted to the load switches.

-Two pulse/analogue converters receive signals from Ontario Hydro billing meters and send analogue signals, proportionl to kW demand from two Ontario Hydro transformers, to the Controller. The two signals are added in the computer to provide one signal proportional to total kW demand.

-Since Deep River is a northern town with a high density of electric heating, its demand depends strongly on outside temperature. Therefore, a Resistance Temperature Detector and a temperature transducer are provided to allow the controller to monitor and record outside temperature for later analysis.

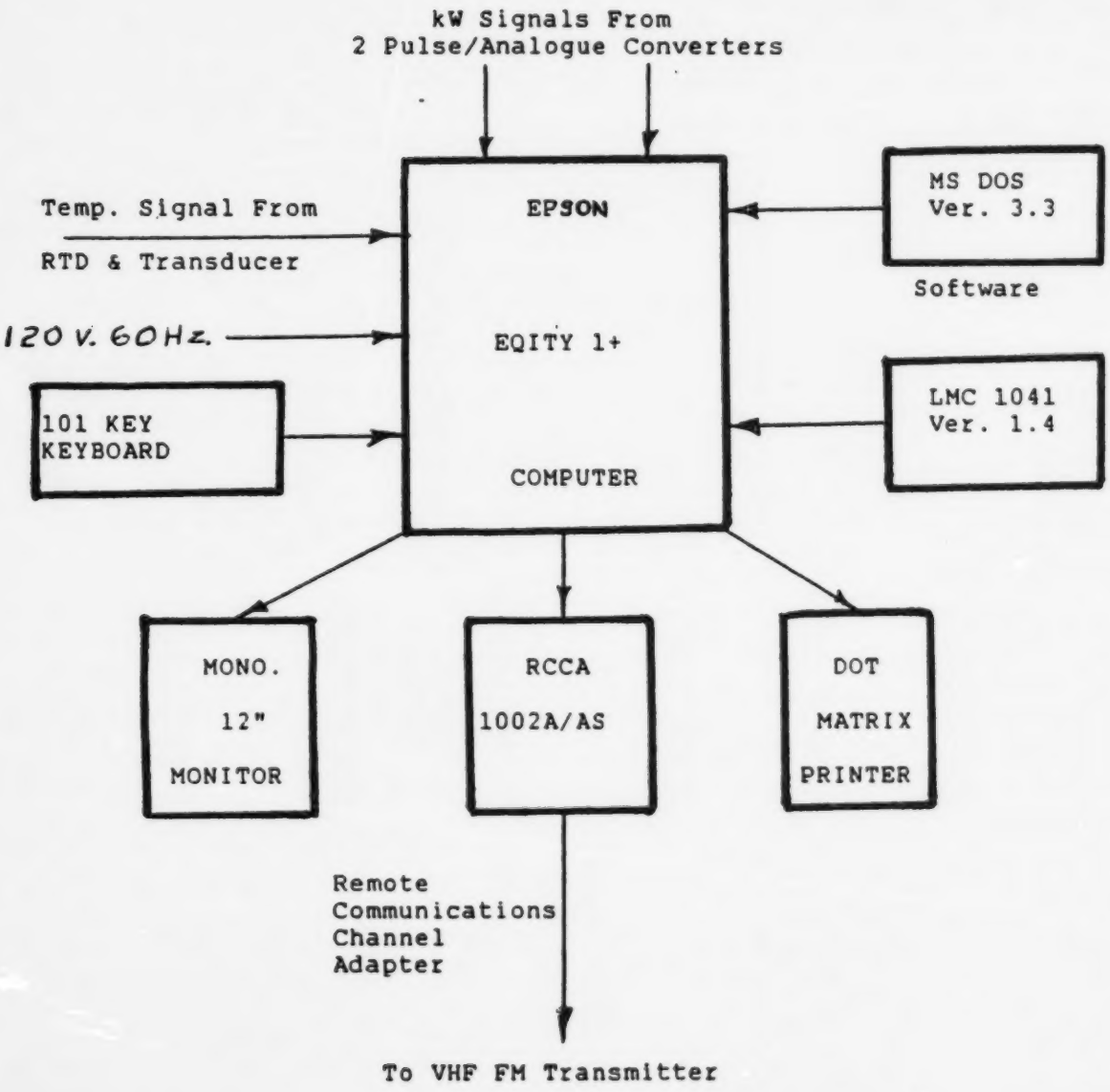
- A Sola 1.2 kVA Standby Power Supply, with back up batteries and a Sola PS 454 six outlet surge suppressor and EMI/ RFI filter, provide reliable, clean power to the LMC Controller

2.2 For a closer look at the Controller, please see the block diagram of the Scientific Atlanta LMC-1041 System.

- The central block shows the Epson Equity 1+ Computer with general specifications as follows:

- IBM Compatible XT
- 8088 Microprocessor
- Operating speed - 4.77 & 10 MHz
- 640 kB RAM Memory
- 3.5" (720 kB) Floppy Disk Drive
- 20 MB Hard Disk Drive

SCIENTIFIC ATLANTA LMC-1041 SYSTEM



- The 101 key enhanced AT style keyboard is ergonomically designed for ease of operation and to minimize operator fatigue.

- The Epson 12 inch monochrome monitor was provided.

- A Star 80 column, dot matrix line printer was provided

- The computer uses the standard MS DOS Operating System, Version 3.3.

-The Scientific Atlanta LMC-1041 Application Software,Version 1.4 is overlaid on the MS DOS operating system. It provides great flexibility in configuring the system to match the local utility characteristics and satisfy its load management strategies.

- The Scientific Atlanta Remote Communications Channel Adapter (RCCA) converts digital messages into audio frequency signals and keys up the Motorola transmitter to broadcast modulated FM signals to the load switches.

- The computer is programmed to record 15 minute demand and temperature readings. Later, this historical data is printed in tabular form, for analysis. It is processed on an off-line computer with LOTUS 123, to yield billing demand in kW, energy in kWH and heating degree days.

2.3 System Installed Capital Cost

- System Hardware and Software	$63,114
- System Installation	$18,750
- Administrative and Clerical Activities	$ 2,402
- Studies, Proposals, Reports and Project Engineering	$19,786
Total Installed Cost in Canadian dollars	$104,052

3.0 Selection and Evaluation of Customers Deferrable Loads for Control

3.1 It was necessary to survey customers loads to select those which could be controlled and to estimate the reduction in demand during utility peak periods. This information was required to determine the number of load switches; the system installed cost, and the control strategy for configuration of the load management controller. It also yields the reduction in billing demand and changes in energy sold, to calculate utility savings and to propose discounts to customers as an incentive for participation in the program. The net savings and pay back period to the utility can then be estimated.

3.2 General principles as follows were developed for the selection of controlled loads.
- Control of selected load should reduce the utility peak demands significantly.
- Control of these loads should not reduce energy sales significantly.
- Control should cause no discomfort, inconvenience or extra cost to utility customers.

3.3.0 It was found that controlled loads fell into four general categories as follows, in decreasing order of desirability.

3.3.1 Energy can be stored for later use.
- institutional, commercial or residential hot water heating
- ice making in skating or curling rinks
- preheating of buildings prior to expected utility peak.

3.3.2 Product can be stored for later use
- filtration of municipal water supply and storage in holding and high head tanks.

3.3.3 Substitution of other forms of energy during peak periods.
- electric/oil boilers in hospitals and other institutions.
- electric/oil furnaces in houses.

3.3.4 Loads with limited energy storage can be deferred for short periods or can be cycled throughout the utility peak period.
- electric space heating in less essential areas, such as corridors in schools and apartment buildings.
- supply and tempering of outside air in building ventilation systems.
- humidification of winter air in institutional buildings
- air conditioning of institutional buildings.

3.4 General Service Loads

It was recognized that the larger Institutional and Commercial buildings contained many relatively large loads which could be controlled more economically than Residential loads, to reduce utility peak demands significantly. The Engineer proposed to survey and evaluate loads in these buildings in co-operation with utility staff and customers and this proposal was accepted by the Commission. The results are shown in the table of Selected Commercial / Institutional Controlled Loads.Proposals were sent to each General Service customer, with a list of selected loads, to secure customer approval.

Selected Commercial/Institutional Controlled Loads

Bldg. (number)	Bldg. Name	Ave.Billing Demand (kW)	Controlled Loads (number)	Connected Controlled Load (kW)
1	Hospital	551	8	609
1	Water Treat. Plant	304	5	396
1	Skating Rink	109	4	130
1	Curling & Squash Club	60	7	91
1	Hotel	410	4	276
4	Municipal & AECL garages	128(4))	12	247
1	Secondary School	553	7	390
3	Primary Schools	462 (3)	24	383
6	Apartment Bldgs.	367 (6)	38	227
19	Totals	2,944.	109	2,749

3.5 Residential Loads

3.5.1 Residential load research data was available in seven Ontario Hydro reports for the Scarborough/Oshawa Field Trials and in AECL reports, based on the electric/oil dual fuel heating experiment in Deep River. Based on this data, four residential loads as follows were evaluated for control
- Central Electric Furnaces (CEF)
- Oil /Electric Furnaces (plenum heaters)
- Single Tank Water Heaters (40 & 60 Gal.)
- Dual Tank Water Heaters

3.5.2 It was decided that control of central electric furnaces would yield insufficient savings to justify the cost of control and possible customer relations problems. However, it was concluded that load management produced significant net revenue for dual fuel furnaces and modest net revenue for single tank water heaters. Since the Commisson did not wish to adopt Time of Use rates for 1989 and expand its water heater rental program, consideration of dual tank water heaters was deferred.

3.5.3 Residential customers were informed about the program through articles in the local press.Dual fuel furnaces and single tank water heaters were selected for control in 25 houses. The utility manager selected the 25 Residential customers based on telephone calls with his customers. See table of Selected Residential Controlled Loads, showing the expected distribution of residential connected loads. Although there are approximately 100 houses with both dual fuel furnaces & electric water heaters, only 25 load switches were available for control of residential loads.

Selected Residential Controlled Loads

Houses (number)	Description of Loads	Connected Load (kW)
6	6 - 15 kW D/F Furnaces	90.0
	4 - 40 Gal. W/H Tanks	15.0
	2 - 60 Gal. W/H Tanks	7.6
4	4 - 10kW D/F Furnace	40.0
	2 - 40 Gal. W/H Tanks	7.5
	2 - 60 Gal. W/H Tanks	7.6
15	15 - 9kW D/F Furnaces	135.0
	15 - 60 Gal. W/H Tanks	56.9
25	Totals	359.6

4.0 Reduction in Demand

4.1 Having selected the deferrable loads for control and knowing their connected load or name plate rating, it is necessary to estimate their diversified demand during utility peak periods. If the load is controlled off throughout the peak period the reduced demand will equal the diversified demand. If a particular load is cycled during peak periods the reduced demand will equal approximately 2/3 of the diversified demand.

4.2 Commercial / Institutional Loads

The following steps were employed to evaluate these loads for control:

- Review the customer's electric utility bills for the past twelve months to establish:
(1) annual billing demand, energy and load factor.
(2) quarterly billing demand, energy and load factor to establish variations over the Winter, Spring, Summer and Fall periods.
(3) any unusual irregularities in consumption throughout the year.

- Monitor critical loads with portable meters, counters or demand and energy recorders to determine daily or weekly patterns of use.

- Review with customer his operating procedures and practices as well as daily and weekly operating cycles.

- If available, review load research data for similar loads and facilities.

- Estimate diversified demand based on the above findings for:
(1) Winter (3 months)
(2) Spring/Fall (6 months)
(3) Summer (3 months)

- Decide on control method
(1) Control Off (CO) throughout the utility peak
(2) Cyclic Load Management (CLM) using four hour cycles and 50% duty factor.

- Estimate Reduced Demand equal to:
(1) diversified demand for CO loads
(2) 2/3 of diversified demand for CLM loads

4.3 The results of the above evaluation are shown below for four typical facilities among the 19 G/S customers selected for participation.

Customer	Season	Connected Load	Diversified Demand	Control Method	Reduced Demand
	W	609	282	CO	260
Hospital	S/F	537	157	&	146
	S	501	96	CLM	91
Water	W	396	291	CO	291
Treatment	S/F	396	277		277
Plant	S	0	0		0
St.Mary's	W	129	55	CO	45
School	S/F	129	44	&	36
	S	129	6	CLM	6
Poplar	W	55	31		21
Street	S/F	55	30	CLM	20
Apt.	S	55	23		15

4.4 Residential Loads

The diversified demand and energy consumption of each class of controlled load was estimated to calculate annual power costs,with and without load management. These load characteristics were estimated using the results from the oil/electric Hybrid heating Experiment and demonstration in Deep River and the Ontario Hydro Field Trials in Scarborough and Oshawa. Differences in heating degree days and municipal water temperature, between Scarborough/Oshawa and Deep River were included in the estimates. The Residential load characteristics are summarized in the table below.

Load Description	Average Connected Load (kW)	Season	Diversf. Demand (kW)	Control Method	Reduced Demand
Dual Fuel Furnace	8.21	W S/F S	5.6 4.2 0.0	CO CO CO	5.6 4.2 0.0
Single 40 Gal. H/W Tank	3.75	W S/F S	1.18	CLM	0.76
Single 60 Gal. H/W Tank	3.80	W. S/F S	1.77	CLM	1.14

5.0 Control Strategies

5.1 Automatic control of deferrable loads should control the monthly billing demand within target while maintaining energy sales as high as possible. Demand control must be achieved without discomfort, inconvenience or extra costs to the customers.

5.2 All deferrable loads are classified under three categories as follows:

Category A - Loads such as dual fuel furnaces and air supply fans and heaters, which require no "pay back" of energy after they are reconnected. Control of these loads result in 100% loss of retail revenue during "off" periods.

Category B - Loads such as electric space heating and air conditioning which require 70% to 100% "pay back" of energy after they are reconnected because the building air temperature changes slightly to reduce building heat losses or gains. Control of these loads is assumed to lose approximately 15% of retail revenue during "off" periods.

Category C -Loads such as water heaters which have sufficient thermal storage capacity to require 100% "pay back" of energy after they are reconnected. Category C loads also include ice making, water purification and pumping loads. Control of these loads causes no loss of retail revenue.

5.3 When a number of Category B or C loads are restored after a period of control, the initial demand or "flyback" can be up to two times the diversified demand discussed in Section 4.0. This increased demand, on restoration of loads, must be considered when configuring the LMC-1041 program.

5.4 Deferrable loads are also classified according to one of two control methods as follows:

"Control Off" during utility peak (CO)

"Cyclic Load Management" (CLM)
Certain air supply fans and heaters, space heaters and water heaters, are controlled off for two hours maximum followed by reconnection for two hours, during utility peak periods to avoid inconvenience or discomfort to building occupants.

5.5 Finally, all customers and their deferrable loads are allocated to electrical distribution feeders #1 to #5, based on the building location in Deep River.

5.6 It is possible to allocate 256 computer addresses to load groups for control. It was decided to employ only 65 of these initially, for operating simplicity and to make ample provision for future allocations. The table below shows how these 65 addresses were allocated to three load categories (ABC) and two control methods (CO & CLM).

Allocation of Addresses to Load Categories and Control Methods
In LMC-1041 Load Management Computer Program

Control Method \ Category	A	B	C	Totals
CO	#7 to #24	#25 to #37	#38 to #52	
	18	13	15	46
CLM	#53 to #54	#55	#56 to #71	
	2	1	16	19
Totals	20	14	31	65

5.7 Controlled loads have been assigned to computer addresses to meet the following requirements:

(1) Each address shall include only General Service or Residential loads to simplify load analyses.

(2) Each address shall include only loads of one Category A, B or C as defined in Paragraph 5.2 above.

(3) Each address shall include only loads of one Control Method CO or CLM as defined in Paragraph 5.4 above.

(4) Each address shall include only loads connected to one of five distribution feeders #1 to #5.

(5) Loads in each building or facility shall be assigned two or more addresses to avoid excessive billing demand due to flyback when controlled loads are restored.

(6) Large, small and zero kW loads shall be distributed evenly over the 65 addresses to provide smooth control over the full operating range. This will also make percentage addresses activated, approximately equal to percentage load controlled, for system analyses. Addresses in the same building or facility are separated to avoid excessive flyback on restoration of load.

5.8 Since electric space heating represents a large fraction of Deep River connected load, the highest billing demands occur on the coldest days, normally between 7 and 9 AM. Therefore peak demand days can be expected when weather reports predict low temperatures for the next day. The following tables show two automatic control sequences which can be selected, based on predicted outside temperature.

Expected Peak Demand Days
Based on Predicted Low Outside Temperatures

Sequence #1	Category & Control Method	Load Groups
1	A - CO	18
2	C - CO	15
3	B - CO	13
4	A - CLM	2
5	C - CLM	16
6	B - CLM	1
Totals		65

Non Peak Demand Days

Sequence #2	Category & Control Method	Load Groups
1	C - CO	15
2	B - CO	13
3	A - CO	18
4	C - CLM	16
5	B - CLM	1
6	A - CLM	2
Total		65

5.9 Automatic sequence (1) will disconnect Category A loads for longer periods and reduce the quantity of "pay back" energy required on peak days. Sequence (2) will minimize control of Category A loads and maximize energy sales on non peak days.

5.10 During system emergencies or tests, all deferrable loads can be disconnected simultaneously by a "scram" command at the computer console. Similarly,loads controlled by specific computer addresses can be controlled to unload selected load groups or distribution feeders. "Cold" load pick up", programmed on each load switch, delays reconnection of deferrable loads, following a power outage, by 15 + or - 1.5 minutes. Failure of the load switch, transmitter or computer will return all controlled loads to their normal state, within the timeout period.

6.0 Utility Savings

6.1 Annual reduction in wholesale cost of power, attributable to all customers, may be calculated with the formula:

$$[(3 * Dw) + (6 * Ds/f) + (3 * Ds)] \$12.79$$

where Dw = Average demand reduction in kW in Winter months
Ds/f = Average demand reduction in kW in Spring/Fall months
Ds = Average demand reduction in kW in Summer months
$12.79 = Wholesale demand rate in dollars per kW/month, applicable to Deep River Hydro in 1988

6.2 For example, the annual reduction in the wholesale cost of power applicable to the Hospital (discussed in Section 4.3) can be estimated as follows.

$$(3*260. + 6*146. + 3*91.) \$12.79 = \$24,672.$$

where 260, 146 & 91 are the estimated reduced demands for Winter, Spring/Fall and Summer months, respectively.

6.3 The above formula is applicable if load management does not change the energy consumed. If a residential dual fuel furnace is controlled, substitution of oil for electricity during peak periods will reduce the consumption of electricity. In this case, calculate and subtract the wholesale cost of power from retail revenue to yield net revenue. Perform this calculation using demand and energy values, with and without load management, to yield the increase in net revenue with load management.

6.4 If we assume that all selected loads are controlled, the annual savings with load management are shown in the table below.

Annual Reduction in Wholesale Cost of Power

Class	Season	Reduced Demand (kW)	Wholesale Savings ($)
General Service	W	1,214.32	
	S/F	950.93	130,474.
	S	284.24	
Residential	W	169.36	
	S/F	132.56	17,230.
	S	14.56	
Totals		1,383.68	
		1,083.49	$147,704
		298.80	

7.0 Customer Discounts

7.1 Ontario Hydro, Deep River Hydro and the Engineer worked together to develop a set of customer discounts which would be fair to the customers, local utility and other utilities in the Hydro Family. The following principles were applied to insure that the discounts would be:
(1) understandable by the customer
(2) non discriminatory between customers
(3) stable over time
(4) sufficiently segmented to reflect costs

7.2 After study of the Engineer's report and proposal, Ontario Hydro agreed to allow the utility to grant participating customers a maximum discount of $4.00/kW, based on the estimated reduction in utility billing demand. To satisfy principle (1) it was agreed that:

Discount = Discount Rate * Connected Load

To satisfy principle (4), it was agreed to segment the rates according to three seasonal periods used in the Engineer's report. For General Service customers, the discount rate was developed by customer class. For residential customers, the discount rate was developed for end uses, including dual fuel furnaces and single tank water heaters.

7.3 The two tables below show the composite discount rates for Commercial/Institutional Customers and Residential Loads.

Commercial/Institutional

Rate = $/kW/month of Controlled Connected Load

Customer Class		Winter	Spring & Fall	Summer
Curling Club, Schools and Mun. Garage	(1) (4) (1)	1.75	1.40	NIL
Hospital	(1)	1.55	1.10	0.75
Apartments	(7)	1.45	1.40	1.20
AECL Bldg.	(3)	1.85	1.35	0.60
Arena	(1)	2.55	1.70	NIL
Water Treat. Plant	(1)	2.90	2.75	NIL

Residential

Rate = $/Month	Winter	Spring/Fall	Summer
Rate = $ / Appliance / Month			
Water Heaters			
Both 40 & 60 Gal.	2.50	2.50	2.50
Plenum heaters			
5 kW	14.00	14.00	NIL
9 - 10 kW	17.50	17.50	NIL
15 kW	22.00	22.00	NIL

8.0 Results

8.1 Load Factor Improvement

Let us compare actual and predicted monthly load factors without and with load management, for the period July /87 to June /88. Assume that all selected loads were controlled. The results are shown in the table below which reveal a 7% maximum possible increase in average annual load factor.

Period	Without L.M. Peak kW	Without L.M. Actual Load Factor	With L.M. Max. Dem. Reduction kW	With L.M. Predicted Load Factor
July 87	5,240	0.706	298.80	0.748
Aug. 87	4,925	0.716	298.80	0.762
Sept.87	5,835	0.641	1,083.49	0.788
Oct. 87	9,370	0.597	1,083.49	0.675
Nov. 87	11,330	0.636	1,083.49	0.703
Dec. 87	13,875	0.612	1,383.68	0.680
Jan. 88	16,150	0.586	1,383.68	0.641
Feb. 88	14,430	0.671	1,383.68	0.743
Mar. 88	13,635	0.586	1,083.68	0.637
Apr. 88	8,855	0.639	1,083.68	0.728
May 88	7,135	0.555	1,083.68	0.654
June 88	5,540	0.679	298.80	0.717
Average Annual Load Factor approx.		0.635 64%		0.706 approx. 71%

8.2 Net Utility Savings

The following table shows the estimated gross annual utility savings; the customer discounts based on the composite discount rates and the net utility savings. These figures assume that all selected deferrable loads are controlled. 1988 wholesale rates were used.

	General Service Customers $	Residential Customers $	Totals $
Savings in wholesale cost of power	130,474.	17,230.	147,704.
Customer Discounts	39,030	4,931	43,961
Net Utility Savings	91,444	12,299	$103,743

Therefor the estimated system payback is equal to

System Capital Cost / Estimated Annual Savings

= $104,052 / $103,743 = approximately one year.

8.3 Because customer discounts were not in effect in 1988, only 30 of the 55 load switches were installed and 22 of these were in houses controlling relatively small loads. The system was operated intermittently from October 88 to May 89, because of computer hardware and software problems. Prior to shipment, Scientific Atlanta changed from Hewlett-Packard hardware and software to Epson computer hardware and the MS-DOS standard operating system. They also upgraded their application software from LMC-1040 to LMC-1041. This major conversion was responsible for most of the system problems which, were corrected by Scientific Atlanta and the system has operated normally since May 1989, with minor problems.

8.4 Customer discount rates were developed in February 1989. Official approval to pay the discounts to participating customers retroactive to January 01/89, was received from Ontario Hydro in June 1989. Contracts between the utility and its customers were prepared and issued to customers for their review, discussion and agreement. Contracts were signed to allow control of the selected deferrable loads by September 1989. Installation of the remaining load switches is proceeding and all 55 should be in operation by December/89.

8.5 System effectiveness has been limited by the relatively small number of loads under control and by system hardware and software problems until May 1989. While the utility load factor was increased marginally during the "run in" period, it is estimated that the average annual load factor can be increased by as much as 7%. Continuous operation for one year, with most of the selected loads under control, will be necessary for a realistic comparison of actual and predicted performance. System tests will be performed early in 1990 to determine the actual winter performance.

CLOSING REMARKS AND SYNOPSIS

BY

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TECHNICAL SERVICES AND DEVELOPMENT

ONTARIO HYDRO

AT

INNOVATIONS IN DISTRIBUTION LOAD MANAGEMENT SEMINAR

WEDNESDAY, NOVEMBER 29, 1989

SKYLINE AIRPORT HOTEL

TORONTO, ONTARIO

CLOSING REMARKS AND SYNOPSIS

LADIES AND GENTLEMEN, TODAY YOU HEARD IN OVERVIEW AND CASE STUDIES AND IN TECHNOLOGY SPECIFIC PAPERS, SOME MOST INNOVATIVE DEVELOPMENTS IN DISTRIBUTION SYSTEM LOAD MANAGEMENT. THIS HAS BEEN A VERY EFFECTIVE SAMPLING OF THE STATE OF THE ART. IN MY CLOSING REMARKS, LET ME TRY AND PUT THESE DEVELOPMENTS IN A BROADER DEMAND MANAGEMENT SETTING AND EXTEND THE VIEWPOINT BEYOND THE SYSTEM OPERATIONS BENEFITS WHICH YOU HAVE HEARD TODAY.

LOAD MANAGEMENT IS ABOUT CHOICES. IT IS THE COORDINATED EFFORT TO WORK OUT A NEW DEAL BETWEEN CUSTOMERS AND UTILITY TO MUTUAL ADVANTAGE.

WE HAVE ENTERED AN ERA WHERE ACCORDING TO ELECTRIC POWER RESEARCH INSTITUTE THE CUSTOMER IS NOT A METER, OR AN APPLIANCE, ANY LONGER. THE CUSTOMER HAS NEEDS AND THE ENTHUSIASM TO VOICE DISCONTENT WHEN THE NEEDS ARE NOT MET. WITH ONLY A CURSORY EXAMINATION OF LOAD MANAGEMENT IT IS CLEAR THAT CUSTOMERS ARE NOT IMMEDIATELY AND ENTHUSIASTICALLY GOING TO ENDORSE THE CONTROL PROCESS UNLESS THE BENEFITS AND THEIR DISCRETION IS RESPECTED. TO PARAPHRASE GEORGE ORWELL - "BIG BROTHER IS SWITCHING YOU" - IS NOT A GOOD WAY TO POSITION THESE NEW DEVELOPMENTS. MOREOVER, WE, THE UTILITIES, START FROM A POSITION WHERE THE DIFFUSED NATURE OF ELECTRICITY USE IN THE CUSTOMER PREMISES MAKES THE CHANGE IN APPROACH HARDER TO INITIATE.

HOW DO WE GET THE BEST OUT OF LOAD MANAGEMENT? I BELIEVE WE MUST ENCOURAGE TWO THRUSTS:

- INVOLVE THE CUSTOMER IN THE OPPORTUNITIES TO MANAGE CONSUMPTION PATTERNS. OFFER EXTERNAL CONTROL AND CUSTOMER CONTROL OPTIONS.

- o COORDINATE THE DEVELOPMENT OF ALL THE PIECES.

THE 5 TECHNOLOGIES WHICH WILL MAKE THE HIGHEST RANGE OF OPTIONS POSSIBLE ARE:

- o UTILITY CONTROL STRATEGIES
- o COMMUNICATIONS DEVELOPMENT.

BOTH OF THESE TOPICS HAVE BEEN WELL EXPLORED TODAY.

BUT LET'S NOT FORGET THE OTHER THREE:

- o INNOVATIVE METERING
- o INTELLIGENT BUILDING CONTROL SYSTEMS
- o ENERGY STORAGE IMPROVEMENTS

COORDINATED DEVELOPMENT IN ALL FIVE AREAS WILL ENHANCE THE LOAD MANAGEMENT UPTAKE RATE GREATLY. CHIP TECHNOLOGY AND FIBRE OPTICS ARE BRINGING COST PER FUNCTION AND PER UNIT OF DATA TRANSFER DOWN IN LEAPS AND BOUNDS.

IN THE NEAR FUTURE, COMPATIBILITY OF THESE FIVE PIECES OF THE PUZZLE WILL BECOME A BIG ISSUE.

PLEASE NOW CONSIDER THE KEY IN THE PUZZLE, WE CALL IT THE GATEWAY. ON THIS, MY ONLY VIEWGRAPH, WE SEE THE WAY IN WHICH COORDINATION OF THE MANY PROPRIETARY PRODUCTS AND PROTOCOLS COULD BE ACHIEVED. (FIG 1)

THE PROJECT NOW UNDERWAY WITH PLEXUS RESEARCH UNDER CONTRACT TO ELECTRIC POWER RESEARCH INSTITUTE AND EDISON ELECTRIC INSTITUTE WILL ESTABLISH IF THIS PIECE IS VIABLE. BE IT NOT, THEN THE TASK OF TYING TOGETHER ALL THE PIECES WILL BECOME ONEROUS INDEED.

IN THE 1990s WE CAN ENTER A NEW LEVEL OF COMMUNICATIONS WITH CUSTOMERS AND START TO CREATE A NEW ERA OF SERVICE OFFERINGS.

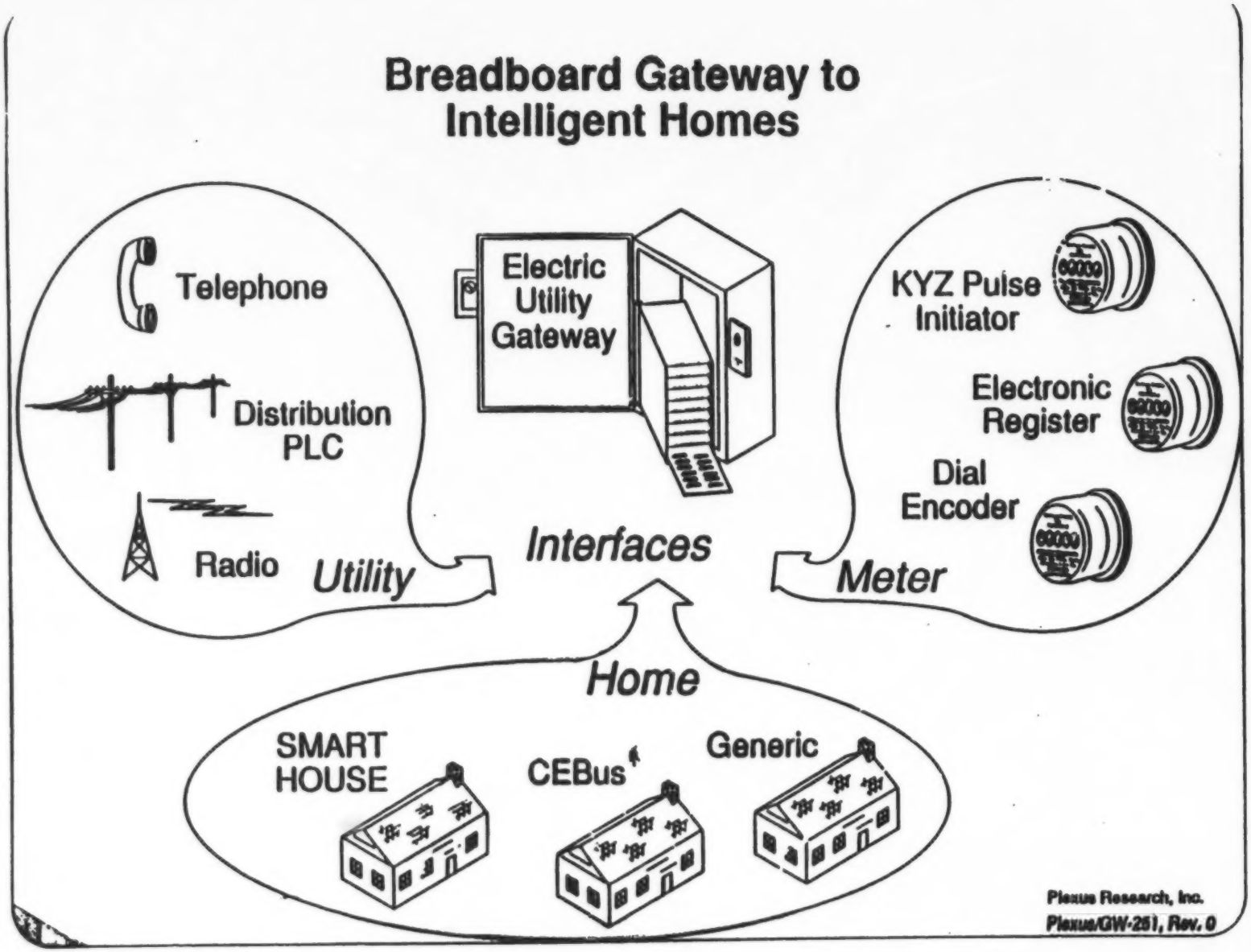
AT A WORLD FUTURES CONFERENCE IN WASHINGTON THIS SUMMER, DR. SIOSHANSI FROM SOUTHERN CALIFORNIA EDISON OUTLINED THAT UTILITY'S MISSION 2000 TO ESTABLISH FIBRE OPTIC LINKS WITH MUCH OF THE CUSTOMER BASE. IN SO DOING THEY WILL CREATE THE MOST FLEXIBLE AND EFFECTIVE NEW CHANNEL WITHIN WHICH TO "UNBUNDLE" THEIR SERVICE OFFERINGS. THE CHANGE HAS THE POTENTIAL TO DO FOR THE ELECTRICITY BUSINESS WHAT THE NETWORK COMPUTER HAS DONE FOR AIRLINES AND FOR THE BANKING BUSINESS. IT COULD CREATE A REAL TIME RELATIONSHIP.

EVEN THOUGH LOAD MANAGEMENT HAS BEEN AROUND FOR OVER 20 YEARS, THERE ARE THOUGHT TO BE NO MORE THAN 4 MILLION CUSTOMERS SO INVOLVED IN NORTH AMERICA. PRICING DEVELOPMENTS, SERVICE FLEXIBILITY AND INFORMED CUSTOMERS ALL ENHANCED BY NEW TECHNOLOGY DEVELOPMENTS WILL SPEED US TO A MUCH HIGHER USE OF LOAD MANAGEMENT INITIATIVES.

REAL TIME COMMUNICATION FOR USAGE RATES, BILLING, ENERGY CONTROL DATA, ITEMIZED USAGE (TELEPHONE BILLS) WILL UPDATE THE ELECTRICITY PURCHASE TRANSACTION TO BRING OUR RELATIONSHIPS WITH CUSTOMERS TO THE 20TH CENTURY AND FURTHER ASSIST UTILITIES IN OPERATING THEIR GENERATION, TRANSMISSION AND DISTRIBUTION SYSTEMS WITH HIGHEST EFFICIENCY.

LADIES AND GENTLEMEN, I BELIEVE WE HAVE AN EXCITING ERA AHEAD IN LOAD MANAGEMENT DEVELOPMENT. THE PACE WILL QUICKEN IN ONTARIO AS THE ONTARIO HYDRO DEMAND/SUPPLY PLAN GOES THROUGH THE STAGES OF PUBLIC APPROVAL. LET'S ALL WORK TOWARDS A COOPERATIVE OUTCOME.

ON BEHALF OF THE UTILITIES HERE TODAY, MAY I THANK JACK KLIEB, BOB GREVEN AND THE MINISTRY OF ENERGY FOR HOSTING SUCH A FINE CONFERENCE ON A VERY TIMELY TOPIC.



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